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THE ECONOMICS OF HOME SOLAR WATER HEATING

THE GEOGRAPHY OF CLIMATE, FUEL PRICES, AND TAXES

by
Gene R. Heinze Fry

Department of Agricultural Economics
Cornell University Agricultural Experiment Station
New York State College of Agriculture and Life Sciences
A Statutory College of the State University
Cornell University, Ithaca, New York, 14853

ABSTRACT

Solar/electric and solar/gas residential water heating were found to be preferred investments to electric and gas water heaters, respectively, in 44 of 69 and 5 of 69 U.S. cities in the study. This finding uses net present value financial criteria and linked engineering and finance models. The base case findings are strongly influenced by regional and state variations in tax credits and deductions, fuel prices, and climate. Solar economics are more widely favorable where homes have large volumes of water use, when real interest rates are much less than 6% per year, if the real price of oil increases in the near term, if operation and maintenance costs are less than projected, if initial costs fall, or if fuels are priced in accordance with the marginal cost of new supplies. They will be less favorable if tax credits are eliminated, and for households not in high marginal tax brackets. The outlook for the rest of the century is not very different from that today.

The engineering model uses average monthly climate data and operates iteratively each half hour on the fifteenth day of each month, to approximate operation over the year. Optimum solar/electric and solar/gas water heating systems were estimated for each location, using net present value criteria, choosing among four sizes and six types of collectors. Use of a preheat/solar storage tank with a standard water heater, plus a low thermostat set temperature (116°F), was found to yield far superior performance in most locations.

The financial model estimates costs of capital, operation, and maintenance and repair, fuel savings, tax savings, and net savings over a 20-year time span. Capital costs and operating energy vary with system type

and size. Maintenance and repair costs vary also with cold stress, heat stress, and years in service. In the first year or two, maintenance costs are high and fuel displaced is low, reflecting expected problems. The present value of tax savings as a fraction of initial investment varies by state, from 57% to 94% of installed system cost.

Electric savings exceed capital costs only in San Diego, and only in Honolulu are gas savings even half of capital costs. In some cities, estimated operation and maintenance costs exceed gas savings. Climate differences, influencing water supply temperatures, result in more fuel displaced in 17 cities than a conventional heater uses in Miami. A measure of the relative importance of tax savings, fuel prices, and climate is that a solar investment makes far more financial sense in Duluth than in Las Vegas.

Base case assumptions include 230 liters/day of hot water use, $45,000 taxable income, relative regional fuel price differences declining over time, financing by a 20-year loan at 13% interest, 7% per year general inflation, real gas price inflation of 9% per year for three years and 2% thereafter, and 1.5% per year real electric price inflation.

The presence of tax credits probably inflates the prices of solar hot water systems. Without tax credits, solar systems would be economically viable investments only in Hawaii, on the California coast, and perhaps a few other places. However, if fuel prices were then based on the marginal cost of new supplies, solar systems would be almost as competitive as they are now: with tax credits but with rolled-in average cost pricing. Where solar water heat is chosen, 1) the household uses lots of hot water, 2) the place is on the south Pacific coast, 3) the place is far from natural gas mains, or 4) non-economic criteria are quite important to the solar buyer.

ACKNOWLEDGEMENTS

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ERRATA

Page	Location	Text	Correction
48	Ex. 11b	$11.98	$15.49
	Ex. 12	$11.98	$15.49
	Ex. 12	$158.50	$204.94
50	Ex. 19	$158.50	$204.94
	Ex. 19	209.70	163.26
	Ex. 21	209.70	163.26
	Ex. 21	78.88	61.41
73	Seattle (Net Saving)	-103	-124
91	note #7	19.159	19.186
92	note #7	19.159	19.186
	note #7	1.1624	1.1641

I. INTRODUCTION

Background for the Study

In 1984, ten years after the first explosive oil price increases, the solar energy industry in the United States is small and concentrated in a few areas. It may be cheaper for society to use solar energy for many applications than to develop new deposits of oil and natural gas, including new gas deposits whose extraction costs may be double or triple the current average wellhead price. In addition, solar energy may cut our reliance on uncertain energy imports. In response to these and other reasons, the federal government and many state governments have provided tax credits to encourage the use of solar energy and other renewable resources. Debate is under way in Congress about whether to extend federal tax credits due to expire in 1985.

Among important questions in this debate are 1) Where is solar heating now cost competitive against natural gas and electricity? 2) How do varied assumptions about use levels, financing arrangements, and future price increases affect the cost competition? 3) What is the role of tax credits and other tax savings in this picture? 4) Are tax credits justified to aid the solar industry? If so, why and how much?

This study addresses these questions, with emphasis on taxes and geography. It looks only at water heating in homes by flat plate solar collectors, using a natural gas or electric resistance backup, as probably the most cost competitive application now. The criterion, the measure of cost effectiveness, is net present value (NPV), and its variant, annualized costs. Solar/gas* domestic hot water (DHW) systems are assumed to compete with gas

*Solar DHW system with conventional gas water heater for a backup.

FIGURE 1. Cities in This Study

TABLE 1. Examples of Present Values and Annualized Costs

(PV = Present Value)

Present Values

Year	Cost of Solar	Cost of no Solar	Solar Net Saving	Present Values: Cost of Solar	Present Values: Cost of no Solar	Present Values: Solar Net Saving
0	$1000	$ 0	$-1000	$1000.00	$ 0.00	$-1000.00
1	30	300	+ 270	27.27	272.73	+ 245.45
2	40	400	+ 360	33.06	330.58	+ 297.52
3	50	500	+ 450	37.57	375.66	+ 338.09
4	60	600	+ 540	41.07	410.68	+ 369.61
				1138.97	1389.65	+ 250.67

Annualized Costs

Year	Fuel Cost	PV of Fuel Cost	Annualized Fuel Cost	PV of Annualized Fuel Cost
1	$300	$272.73	$438.39	$398.54
2	400	330.58	438.39	362.31
3	500	375.66	438.39	329.37
4	600	410.68	438.39	299.43
		1389.65		1389.65

Annualized Savings

Year	Net Saving	PV of Net Saving	Annualized Net Saving	PV of Annualized Net Saving
0	$-1000	$-1000.00	$+ 60.11	$+ 60.11
1	+ 270	+ 245.45	+ 60.11	+ 54.65
2	+ 360	+ 297.52	+ 60.11	+ 49.68
3	+ 450	+ 338.09	+ 60.11	+ 45.16
4	+ 540	+ 369.61	+ 60.11	+ 41.06
		+ 250.67		+250.66

\$272.73 now, since a loan of \$272.73 would have to be repaid with \$272.73* (1.10) = \$300.00 in one year. Similarly, the present value of \$400 in two years is $\$400/(1.10^2) = \$330.58$. The net present value of the investment can be found in two ways: by adding the present values of the differences between investing or not each year (last column), or by adding the present values of each strategy and subtracting one total from the other. The result is the same: \$1389.65 - \$1138.97 = \$250.67 with rounding error. The net present value, \$250.67, is positive, so the investment is recommended.

Table 1 also illustrates the concepts of annualized costs and annualized savings, which are derived from present value. Note that some columns of the bottom tables come from the top table. By definition, if the net present value of an investment is positive, the annualized cost of the investment is less than the annualized cost of not investing. The annualized fuel cost is the sum of the present values of fuel costs, divided by an annualizing factor:

$\$438.39 = \frac{\$1389.65}{3.1699}$, where $3.1699 = \frac{1}{1.1^1} + \frac{1}{1.1^2} + \frac{1}{1.1^3} + \frac{1}{1.1^4}$. Similarly,

the annualized net saving is $\$60.11 = \frac{\$250.67}{4.1699}$, where $4.1699 = \sum_{i=0}^{4} \frac{1}{1.1^i}$.

In general, the annualized cost is the sum of the present values of the costs, divided by $\sum_{i=1}^{I} (1+r)^{-i} = \frac{1-(1+r)^{-I}}{r}$, where r is the discount rate, i is the period, and I is the total of periods in which the cost occurs, beginning in period 1.

This study measures net costs, the difference in costs between investing in a conventional DHW system and a solar system with conventional backup for periods when solar energy is insufficient. Cole (5) suggests that solar/gas systems probably do not compete against electric heat. Since electric heat is far more expensive than gas, those who use electric heat probably do not have a gas alternative available. This study measures fuel savings from a solar/gas system at the price of natural gas displaced and solar/electric fuel savings at electric prices. Since a backup conventional water heater is assumed with or without a solar DHW system, the difference in capital costs is treated as zero and ignored. A gas water heater is assumed to have a pilot light in a solar/gas system and its alternative, or to have a pilotless ignition in both systems, so that there is no difference in pilot fuel use. So pilot use is also generally ignored.

The American Gas Association (2) reports in their Table 11-9 that 41% of new homes completed during 1980-82 use gas for heating, 50% use electricity, 2.6% use oil, and 6.5% use other sources. Therefore, this study does not examine solar/oil, solar/heat pump, and solar/other systems.

Previous Studies in the Field

Most previous simulation studies of solar finances published from 1970 to 1983 include the economics of solar water heating and solar space heating, using linked engineering and economic models. Each studies several locations, finding solar/electric systems economic in many places, but solar/gas systems cost effective in few places or none. Each study assumes particular real discount rates, real fuel inflation rates, and a set of installed prices for systems of various sizes. The studies differ in types of systems examined, the decision criteria they use, backup fuels considered, and geographical scope of the review. They also differ in their treatment of taxes and assumptions about storage and levels of use. Contrary to expectations by many, estimated system prices in the studies have not shown a downward trend over time.

The major studies are by Tybout and Löf (11), Schulze et al. (9), Bezdek et al. (3), TRW/ERDA (10), and Cohen et al. (4). In addition, Albright (1) of Public Service Company of New Mexico (PSNM) and Hooks (7) of Long Island Lighting Company (LILCO) have reported on pilot field studies by electric utilities.

A comparison of important parameters for the four studies since 1974 is presented in Table 2. The results show the number of cities or states in that study where a solar DHW investment is warranted, under the given assumptions.

Several decision criteria are used to 1) find the optimal solar system and 2) determine if that is preferred to a conventional system. Discounted Life Cycle Cost (LCC) is equivalent to Net Present Value for decision making. LCC adds to NPV the costs common to both alternatives. For example, in Table 1 the discounted LCC of the solar investment is $1138.97 over four years, while the discounted LCC of not making the investment is $1389.65. Years to positive annual saving is the number of years until fuel and other savings that year outweigh capital plus O&M costs that year. Payback period is the time until accumulated savings exceed initial investment. Years to down payment is the number of years until accumulated savings exceed the down payment. The discount rate that makes NPV = 0 is the (internal) rate of return.

The studies generally found solar DHW systems cost competitive against electricity more often than not. But only Schulze for future years and TRW for systems costing $10/ft^2 of collector found solar systems competitive against gas.

The real discount rates used show a rising trend over time, the fuel

TABLE 2. Comparison of Reports on Solar Heating Simulation Studies

Report	TRW (ERDA)	Schulze *et al.* (U.S. Congress) (U of New Mexico)	Bezdek Hirshberg Babcock	Cohen *et al.* (Gas Research Institute) (Thermo Electron Co)
Year Published	1976	1977	1979	1983
Results: Invest in Solar DHW Systems in		@2.5% real discount @4.0%		(4 cities)
vs. Electricity	12 of 13 @ $10/ft^2$ 12 of 13 @ $15/ft^2$ 12 of 13 @ $20/ft^2$ cities	3+ of 48 -1976- 0+ of 48[a] 27+ of 48 -1985- 13+ of 48 30+ of 48 -1990- 20+ of 48 states states	4 of 4 one-family 2 of 4 multi-fam. cities	4 of 4 thermosyphon 4 of 8 draindown 2 of 8 indirect-int[b] 2 of 8 indirect-ext
vs. Natural Gas	8 of 13 @ $10/ft^2$ 5 of 13 @ $15/ft^2$ 0 of 13 @ $20/ft^2$	3 of 48 -1976- 0 of 48 27 of 48 -1985- 13 of 48 30 of 48 -1990- 20 of 48	0 of 4 one-family 0 of 4 multi-fam.	0 of 28 all systems
vs. Heating Oil	13 of 13 @ $10/ft^2$ 5 of 13 @ $15/ft^2$ 0 of 13 @ $20/ft^2$	-----------------	1 of 3 one-family 1 of 3 multi-family	------------
Economic Feasibility Criteria				
1) to determine the optimal solar DHW system	sized to minimize Life Cycle Cost	sized for Marginal Cost = Marginal Saving	NONE Solar Fraction = 70%	minimize Life Cycle Cost among 6-8 designs
2) to choose between solar & conventional				
Life Cycle Cost	------	$LCC_{solar} < LCC_{not}$	------	$LCC_{solar} < LCC_{not}$
Yrs to + Ann Saving	5	------	3	------
Payback Period	15 yrs	------	10 yrs	reject
Yrs to Down Payment	------	------	5	------
Rate of Return	------	------	15%[c]	reject

TABLE 2. (continued)

Report	TRW	Schulze	Bezdek	Cohen
Economic Parameters Fuel Prices ($/MBtu)[d]	$1976	$1976	$1978	$1982
Electricity	2.52 - 18.64	1.36 - 3.36[a]	not reported	16.77 - 21.82
Natural Gas	1.12 - 3.55		N. R.	4.00 - 5.18
Heating Oil	2.52 - 3.53	-------	N. R.	--------
Real Fuel Price Inflation				
Electricity	4 %/yr	2.2%-9.6%/yr[e]	2 %/yr	.2%-1.0%/yr
Natural Gas	4 %/yr		5 %/yr	3.5%-3.8%/yr
Heating Oil	4 %/yr	-------	2 %/yr	--------
General Inflation Rate	6 %/yr	f	5 %/yr	6.6%/yr
Real Discount Rate	2.5%/yr	2.5%, 4.0%/yr	3.5%/yr	5.0%/yr
Operation and Maintenance Cost[g]	2%	1%	1.5%[h]	1.0-3.8%[i]
Taxes U S Tax Credit	30%	none[j]	30% of 1st $2000 + 20% of next $8000	omit
Marginal U S Income Tax	30%	omit	30%	omit
Solar DHW System Parameters Installed Price	$10/ft² $15/ft² or $20/ft²	$375 + $13.50/ft²	$400 + $22/ft²	$2250 T[k] $2500-3100 D $2800-3400 II $3200-3800 IE
Backup Energy	Electric	Gas, Electric	Gas, Electric	Gas (& Electric)
Storage (gal/ft_c^2)	1.8	1.8	N. R.	1.5 - 2.0
Heat Exchangers	2	1	0	0 - 1[m]
Hot Water Use (gal/day)	85 @ 140°F	80 @ 120°F	80 @ 140°F	75 @ 120°F

TABLE 2. (continued)

NOTES:

a - Schulze _et al_. use the lower of electric and adjusted gas price at any point in time. The adjustment is for a _lower_ seasonal efficiency (assumed 60%) in gas water heaters than in electric ones. The reported price is still generally the gas price. Therefore, solar DHW systems are competitive with electricity in _at least_ as many places as they are with gas.

b - "int" = internal heat exchanger, and "ext" = external heat exchanger

c - Bezdek _et al_. use the internal rate of return criterion for commercially owned multi-family housing, and _assume_ that owners take tax deductions for fuel expenses.

d - The fuel prices shown are the range of base prices, among the cities or states in the study.

e - This is the range of average compound growth rates from 1976 to 1990, among the states in the study. The median growth rate is 6.6%.

f - The study uses constant dollars throughout, so it uses no inflation rate.

g - O&M costs are generally expressed as a fraction of installed capital cost. The cost is figured yearly and is escalated at the general inflation rate.

h - Bezdek says maintenance costs are 1.5% of investment each year. It is not clear whether this includes operating costs.

i - Cohen's maintenance costs follow a schedule, based on system hardware. To this is added 1% of investment for non-system specific maintenance. Operating costs are figured separately, based on system design and location, and are added to the two components of maintenance costs. Operating costs begin at 0.0%-1.0% of investment cost and escalate as electric prices rise. System specific maintenance costs were converted to a fraction of investment cost by assuming a 6% real discount rate.

j - There were no tax credits when the Schulze study was undertaken.

k - T = thermosyphon, D = direct, II and IE = indirect systems, with internal or external heat exchanger.

m - The indirect systems have one heat exchanger each. The other systems have none.

price escalation rates show a mixed trend, and capital costs adjusted for inflation follow an upward trend. The rising discount rates used reflect the objective situation of rising real interest rates over the last decade, to rates as high as 9% in 1983, near an historic high. Many analysts predict continued very high real discount rates as long as massive federal budget deficits continue. Real fuel price escalation rates have varied (8), with steadily rising electricity prices through the period (2.3%/year compound average since 1973), a big jump in oil prices in 1979 followed by decline since (up 5.9%/year average 1973-1983), and a steady large rise in natural gas prices (7.6%/year), now targeted to track the higher price of oil ever more closely under the Natural Gas Policy Act of 1978.

Contrary to expectations of Tybout and Löf in 1970 and most interested parties since then, real installed solar capital costs have not shown a declining trend over time. See Table 3. In fact, actual costs in the 1980's have been substantially higher than any of the costs projected in the 1970's, of which only Bezdek's is reported to be based on field experience. It appears there may have been a major jump in prices about 1980. Prices show substantial scale economies in system purchase. The PSNM study found prices for direct systems half those for indirect systems. Higher prices may reflect higher freeze protection ability and greater reliability, misjudgment of future system price decreases, effects of taxes or credits, and/or other effects. Tybout and Löf may have biased estimates in the 1970's. They found that collectors in the U.S. in 1970 sold for \$6-9/ft^2, but believed costs could fall to as low as \$2/ft^2 by manufacturing improvements without design changes. They projected a future price of a fixed cost plus \$1.30/ft^2, with design changes.

There are many important differences among the studies. Only PSNM and

TABLE 3. Installed Costs of Solar DHW Systems, from Previous Studies

Study	Year	Current $	1983 $	1983 $ for 48 ft^2 system
Tybout & Löf[a]	1970	375 + 7/ft^2	930 + 17.40/ft^2	1765
TRW	1976	20/ft^2	34.00/ft^2	1632
Schulze	1977	375 + 13.50/ft^2	600 + 21.60/ft^2	1637
Bezdek	1979	400 + 22/ft^2	531 + 29.20/ft^2	1933
PSNM[b]	1979	35.88/ft^2	47.62/ft^2	2286
LILCO[c]	1978	1750 (34 ft^2)	76.15/ft^2	3655
LILCO[d]	1981?	2499 (42 ft^2)	64.17/ft^2	3080
Cohen[e]	1983	1600 + 30/ft^2	1600 + 30.00/ft^2	3040

Notes:

a - These figures are researched 1970 prices. Their projections of future prices are $2.00/$ft^2$ or lower.

b - Public Service of New Mexico: 19 systems in study, averaging 59 ft^2. Three of the systems were self-installed. The other 16 averaged 59 ft^2, for an average installed cost of $35.88/$ft^2$.

c - Long Island Lighting Company: 632 systems in the study. "As the program progressed, the systems were priced from $1750 to $2499." In January 1979 the 34 ft^2 collectors were replaced by the 42 ft^2 collectors.

d - It is not clear when the $2499 price prevailed.

e - The price varies, depending on the type of system. $3040 is for an indirect system with internal heat exchanger. A thermosyphon system cost $56.25/$ft^2$, projected $2700 for 48 ft^2. A system with an external heat exchanger would cost $3440.

Cohen have dealt with several different types of systems in the same study. The other reports assume homogenous types, presumably direct water systems or indirect ones with glycol/water anti-freeze mixture. The TRW study and especially Bezdek and Hooks use different decision criteria from this study. Hooks makes no decisions, but only examines fuel savings. Bezdek emphasizes criteria that consumers might use instead of business criteria. He points out that homeowners move every five years on average, so they demand quicker and more certain payoffs than a business might require. Some of the studies treat oil as a backup fuel and some don't. Schulze examines solar feasibility in every state, TRW in thirteen cities, Tybout and Löf in eight cities, and both Bezdek and Cohen in four cities.

The TRW and Schulze studies were done before tax credits were in place, but Schulze, in the study for Congress, ignores the role of income tax deductions for interest paid in financing the purchase. Cohen omits tax considerations entirely, citing the probable phase-out of tax credits.

The studies show a declining trend in modelled daily average water use, capped by LILCO's finding that water use among their 632 homes* declined from an average of 59 gallons/day of hot water to 55 two years later. Modelled storage temperatures vary substantially by study, 120°F to 140°F, and from house to house (as reported by PSNM), in a way that can affect results in a major way.

The current study follows the geographical scope of Schulze, Cohen's scope in system types, the tax treatment of PSNM, Bezdek, and TRW, several studies in choice of decision criteria, and LILCO in levels of water use. It chooses a storage temperature below 120°F. This study optimizes a system by size and type according to the NPV criterion, equivalent to life

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*2-5 persons per home, 4 the most common number.

cycle costing.

The Schulze study is one of the two most detailed. The engineering and price increase models are detailed outside the report. The accuracy of the price model is good (12). The authors recommended several policies: 1) deregulation of energy prices, 2) a windfall profits tax, 3) subsidized solar loans if fuel prices remain regulated, 4) consumer education about life cycle costs, 5) graduated mortgages, and 6) tax subsidies as a last resort. They project .24 or .40 Q* of energy savings from solar DHW by 1990, depending on real interest rates. Market penetration in 1984 is substantially less than they projected. Reasons may be 1) higher real installed costs, 2) higher real interest rates, 3) annual O&M costs based on only 1% of installed costs, and 4) consumer use of more stringent financial criteria suggested by Bezdek. These outweigh very substantial tax benefits not treated in the study.

The other quite detailed study is by Cohen et al. for the Gas Research Institute. It checks storage tank temperature stratification, the heat transfer from gas flame to water, the amount of pilot usage and effects of eliminating a gas pilot in various ways, and the effects of water use patterns concentrated at different times of day. It finds temperature stratified tanks, especially in thermosyphon systems without preventive measures. Stand-by flue losses can equal pilot use if a pilot is eliminated. There is a small detrimental effect on solar fraction† if water use is concentrated at a few times mostly in the morning. Cohen uses a more

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*1 Q = 10^{15} Btu.

†Solar fraction can be defined in various ways. In Cohen and in this study, it means $1 - \frac{\text{fuel use with solar}}{\text{fuel use without}}$

sophisticated treatment of maintenance costs than other studies, adding to 1% of installed cost each year the costs from a replacement schedule for anti-freeze, pumps, and controller. Operating energy is a function of the type of system modelled and the amount of energy collected. Gas water heater seasonal efficiencies* range from 52% to 59%, compared to the 60% Schulze assumes.

The study reports four results of interest. 1) The installed cost of every solar system examined exceeds the life cycle cost of a gas heater. 2) The thermosyphon system has by far the lowest solar LCC, followed in order by a direct system, one with internal heat exchanger, and one with external heat exchanger. 3) Solar/gas systems are cheaper than electric water heaters in 6 of 16 cases, and in all cases with a good pilotless ignition. 4) A solar/electric system has a lower LCC than an electric heater in Miami and Santa Maria, but not Washington or Madison.

Hodges (6) of Dow Corning reports effects of collector fluid choice on corrosion, rupture, pump failure, and fluid replacement intervals. He finds silicone to yield the lowest maintenance and repair costs, closely followed by hydrocarbon oil, with glycols much higher, and ordinary water not even tested. He reports a life cycle cost (not discounted) of $700 more for glycol than for silicone.

Finally, Bezdek observed that solar energy competes with average cost "rolled-in" pricing by electric and gas utilities, insulating consumers from the true marginal cost of fuel supplies. The implication is that the price competition in the market may not be the economically correct one.

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*Seasonal efficiency is the heat (above supply temperature) in hot water for end use, over the year, divided by the energy in the fuel used during the year. See Table 4 for an example.

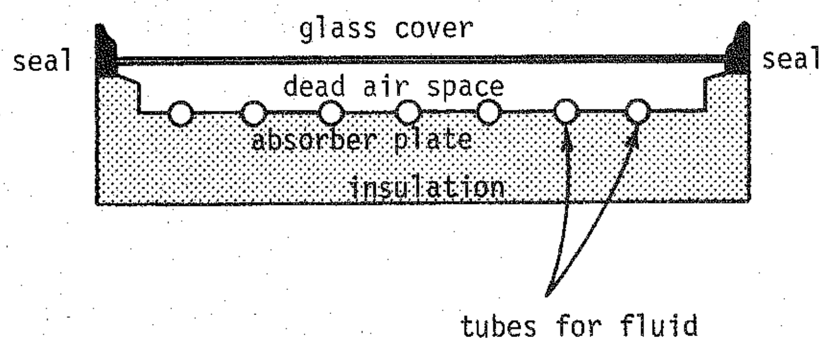
II. THE ENGINEERING MODEL

Orientation to Solar Heat Collection Systems

A system consists of a collector, hot water storage, pipes connecting them, a backup source to heat water when solar input is not sufficient, and usually some controls and a pump. In many cases, there is also a heat exchanger between anti-freeze fluid flowing through the collector and the potable water in the storage tank.

A typical collector is portrayed in Figure 2.

FIGURE 2. Typical Collector: Cutaway Side View



Almost all collectors made in the U.S. today have a single glass cover. The seal maintains a dead air space to minimize heat losses by convection and prevent water from leaking into the collector. Visible light passes through the collector cover and strikes the absorber plate, which is blackened to maximize light absorption. The plate heats up. It emits infrared radiation, most of which is absorbed by the glass. So the plate and the glass will be hotter than the surrounding air. Some absorbers have selective surfaces, which emit little radiation after sunlight strikes them; thus more heat is retained in the plate and less in the glass, cutting down losses to the environment. The absorber plate is most often made of copper, but is sometimes made of aluminum or another material. The plate can be painted black, or given a selective surface with a coating of carbon black or nickel or chromium oxide.

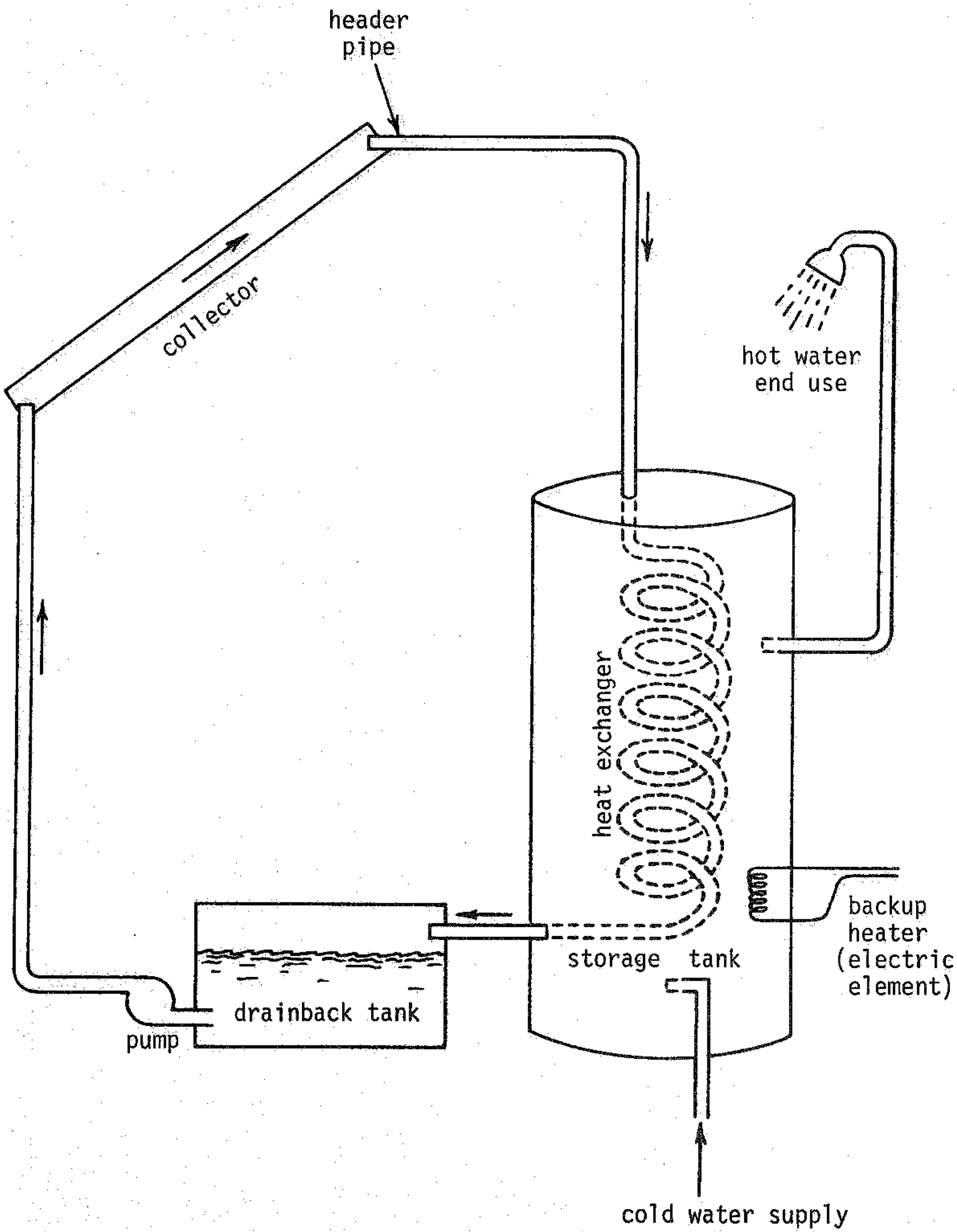
A heat transfer fluid moves through the tubes, picking up heat from the absorber plate. Such collector fluids include ordinary water, which carries the most heat per unit volume, deionized water, anti-freeze solutions containing water and ethylene or propylene glycol, and fluids which neither freeze nor boil under foreseen operating temperatures: hydrocarbon oils and silicones. The tubes have thin walls and are usually copper.

Two or more collectors are commonly joined to form an array. Usually a pair of larger tubes - headers - one at the top and one at the bottom of the array, carry the fluid to and from the individual tubes running through the absorber plate.

Figure 3 shows a typical system, which includes a heat exchanger and a single storage tank containing the backup heater, an electric heating element. Most systems have a controller (not shown) that turns on the pump when the collector is hotter than the water in the storage tank. At other times, the fluid drains from the collector and, in most systems, back into a holding tank.

In the figure, the collector fluid is separated from the water supply by the walls of a heat exchanger, where heat moves from the heated fluid to the cooler water in storage. No exchanger is more than 70% efficient. If the collector fluid is 50° warmer than the water in storage when it enters the heat exchanger and is 18° warmer when it leaves, the exchanger is about 64% efficient. A counterflow heat exchanger, usually mounted outside the tank and using a second pump, is the most efficient. Simpler exchangers,

FIGURE 3. Typical Solar Hot Water System



like the one pictured, would probably have an efficiency of 30 or 35%. Use of such a heat exchanger means the collector would operate at a higher temperature and, therefore, supply roughly 10% less heat to the stored water, compared to using no heat exchanger.

Systems can be classified in several ways: by whether the regular water supply passes through the collector, by characteristics of heat exchangers, by the fluid in the collector loop, by the source of backup heat, by the presence or absence of a pump and/or drainback tank.

In direct systems, the regular water supply system passes through the collector. There is no heat exchanger and there is usually no drainback tank. Thermosyphon is a type of direct system which has no pump; the storage tank is above the collector. Hot water rises through the collector to the tank, while cold water falls from the bottom of the tank to the bottom of the collector. The more common draindown system uses a pump, and storage below the collector.

There are many types of indirect systems, all using a pump, drainback tank, and heat exchanger. The heat exchanger may have one or two walls, and may be the more efficient counterflow type or a less efficient type like crossflow. Possible collector loop fluids include deionized water, glycol-water mixtures, hydrocarbon oils, and silicones. The most common backup fuel is electricity, followed by natural gas and wood.

Another possibility is the presence of a second storage tank, so that one is a preheat tank and the other incorporates the backup heat source. Such an arrangement should collect more heat in less sunny parts of the year. Suppose the thermostat on the backup heater is set to 130°F, but the water temperature in the preheat tank is 100°. The system will be on for the time it takes to heat all the water in the preheat tank up to 130°, when it would not be on in a single tank arrangement.

Orientation to Interaction of Sun and Collector

Two elements determine the power of the sun's insolation on the collector. One is the angle between the sun's rays and the plane of the collector. The other is how much of the sun's radiation comes in direct (beam) form and how much comes in diffuse or reflected form.

The angle the sun makes with the horizontal, α , is a function of the time of day, time of year, and latitude of the site. See Figure 4.

(1) $\sin \alpha = \sin L * \sin \delta + \cos L * \cos \delta * \cos \omega$

L is the latitude, δ is the sun's declination (-23.5° at winter solstice), and ω is the time in angular form (6 AM = +90° and 2 PM = -30°).

The insolation on a horizontal surface, I_h, is found from

(2) $I_h = I_0 * \sin \alpha * K_t$,

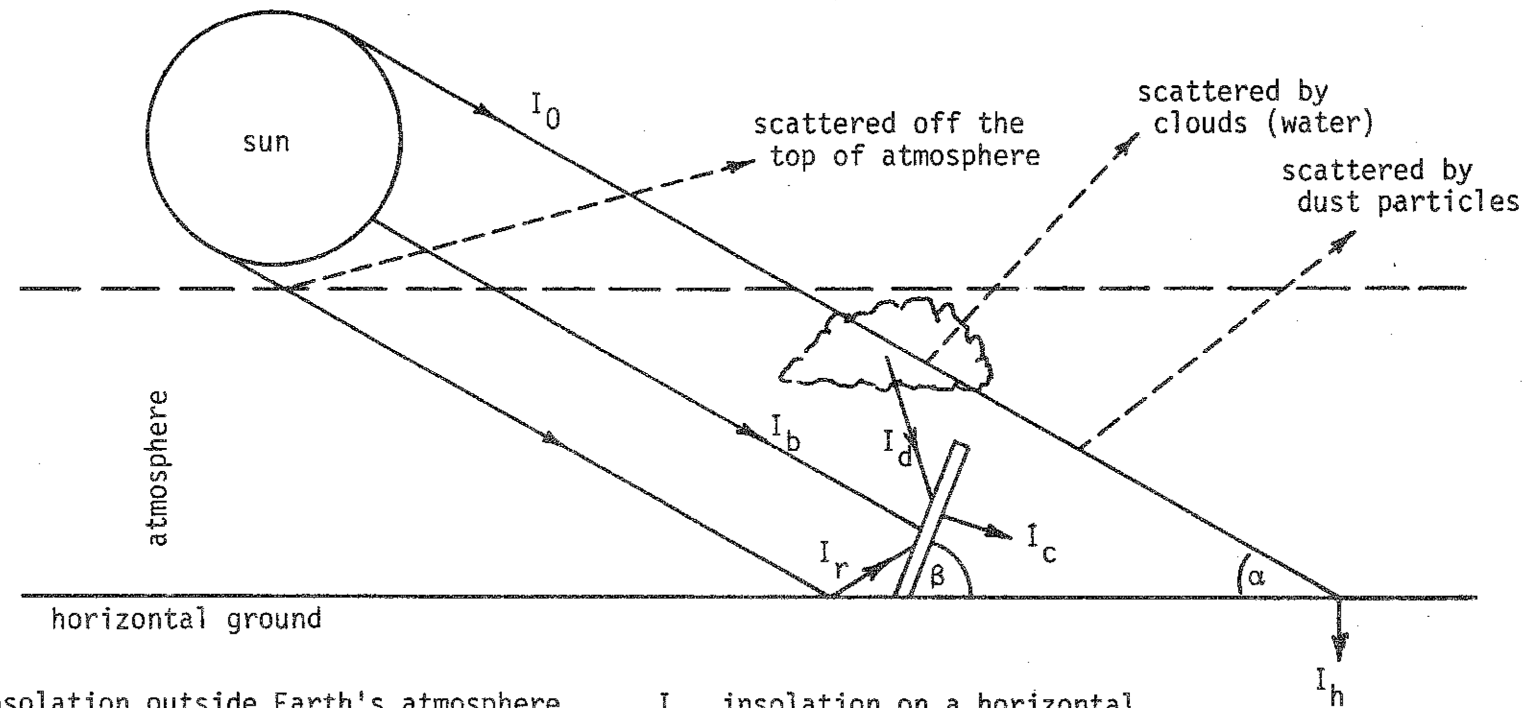
where I_0 is the solar constant adjusted for the elliptical shape of Earth's orbit and K_t is the "clearness" of the atmosphere (1 - albedo). The clearness accounts for scattering off into space by air molecules, clouds, and dust particles. In practice, instruments measure I_h and I_0 as well as α; one deduces values of K_t. The Weather Service compiles hourly readings of clearness in a few locations and monthly averages in many more.

The insolation on a tilted collector is given by

(3) $I_c = I_b*R_b + I_d*R_d + I_r*R_r$

where I_b, I_d, and I_r are beam, diffuse, and reflected insolation. R_b, R_d,

FIGURE 4. Types of Insolation



I_0 insolation outside Earth's atmosphere
I_b beam (direct) radiation
I_d diffuse (refracted) radiation
I_r reflected radiation
I_h insolation on a horizontal surface at ground level
I_c insolation on a tilted collector surface
α angle sun makes with horizontal surface
β angle between collector and horizontal surface

and R_r are tilt factors, to yield the interaction of the collector tilt with the sun angle and mix of radiation types at any moment. Diffuse and reflected radiation are assumed to be isotropic. The reflection tilt factor depends on the reflectivity of the surfaces around the collector.

$$(4)\quad q_c = A * F_R * (\alpha_c * \tau_c * I_c - U_c * [T_i - T_a])$$

The heat collected by the collector at a moment in time is q_c. A is the net (glass) area of the collector. F_R is called the heat removal factor, that part of the heat gain which heats up the fluid rather than the collector hardware itself. τ_c is the fraction of incident sunlight transmitted by the cover and α_c is the fraction of incident sunlight absorbed by the black plate. (Values near .9 for all three are the rule, a little higher for absorbance.) I_c is the insolation on the collector, from Eq. 3. U_c is the collector's conductance of heat to its surroundings. T_i and T_a are the temperatures of the fluid entering the collector and of the air around the collector, respectively.

Due to storage and transport losses, and less than perfect heat transfer from the backup water heater to storage, fuel savings only roughly equal heat collected. Fuel savings (fuel displaced) is the best economic measure of a system's effectiveness. Other interesting measures include solar fraction (percent of fuel displaced) and instantaneous efficiency

$\eta = F_R*(\alpha_c*\tau_c) - F_R*U_c * \frac{T_i - T_a}{I_c}$. (Compare Eq. 4.) A system might collect 12 $\bar{\text{M}}$Btu of heat, displace 10 $\bar{\text{M}}$Btu of fuel, for a solar fraction of 40%, have instantaneous efficiency of $.75 - 7.2 * \frac{T_i - T_a}{I_c} \frac{\text{Watts}}{{}^\circ\text{K*m}}$, and have an annual average efficiency of 50%.

The Simulation Model Used for This Study

The model approximates continuous operation by use of iterations each half hour, on the fifteenth day of the month, for each month of the year, for 69 cities. A complete and detailed description of the model in equation form can be found as Appendix D. The following discussion highlights the working of the model using a diagram and commentary.

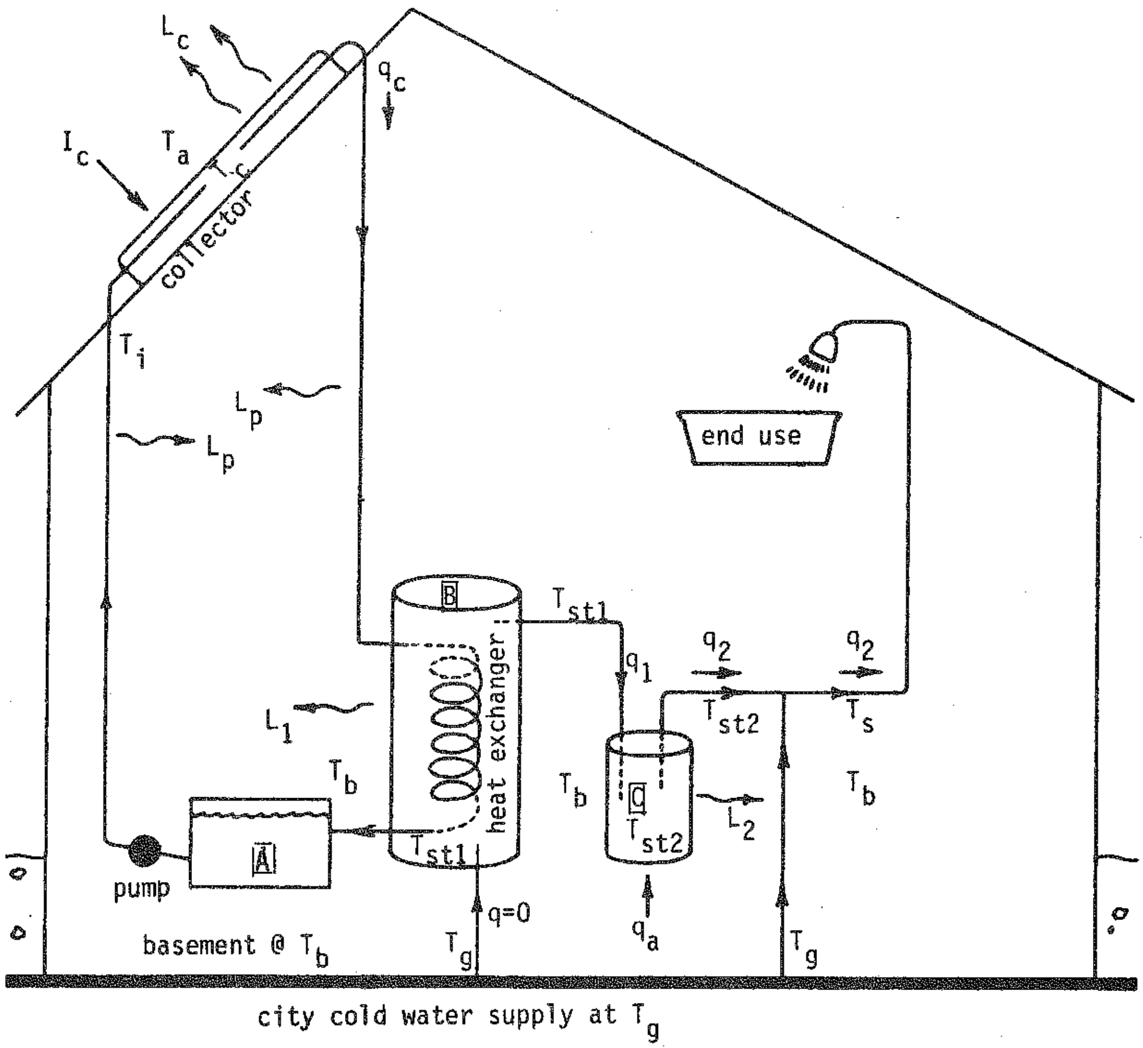
In Figure 5, beginning at the collector, insolation I_c heats up the collector at temperature T_c. The collector loses heat L_c to the surrounding air, changes its own temperature a little, and passes on the rest of the heat, q_c, to the fluid flowing through the tubes in the collector. The loss L_c is proportional to the temperature difference between the collector and the air, $T_c - T_a$.

Enroute from the collector to the storage tanks in the basement, and again returning to the collector, the system loses heat L_p from the pipes to the cooler house. In the heat exchanger in the preheat tank, most of the heat q_c is transferred to the water in storage, decreasing the fluid temperature from just below T_c to just above T_i. In the process, T_{st1}, the temperature of the water in storage, increases a little.

Whenever hot water is used - for showers, cooking, and so forth - water containing heat q_2 is drawn from the backup water tank. If the water is too hot, it is tempered with cold water at temperature T_g to achieve the desired "set" temperature T_s. T_g is the reference temperature, defined as zero, so that q_2 is still the amount of heat transferred to end use.

To replace a volume of water drawn from the backup tank, an equal volume of water is drawn from the preheat tank, which in turn draws an equal volume from the city water supply. The water at temperature T_{st1} flowing to the backup tank contains heat q_1. That flowing into the preheat tank, by

FIGURE 5. Heat Flows in a Collector-Storage System



q = useful heat flow

T = temperature

L = heat loss

A = drainback tank

B = solar preheat storage tank

C = conventional backup water heater

convention, has zero heat.

If the temperature in the backup water tank is now too cold rather than too hot, heat q_a is added by the backup heater, increasing temperature T_{st2} toward or up to the desired temperature T_s.

Meanwhile, both storage tanks are losing heat to the cooler basement where they sit. Heat loss L_1 from the preheat tank is proportional to the temperature difference $T_{st1} - T_b$, as well as to the surface area of the tank and its insulation level. The heat loss L_2 from the backup tank is similar but based on a smaller surface area and proportional to $T_{st2} - T_b$.

Choices of Parameters in the Systems Modelled

Important choices in a solar hot water system include 1) direct or indirect system, 2) type of collector fluid, 3) one or two storage tanks of some size, 4) type and efficiency of heat exchanger, 5) tilt of collector array, 6) array area, 7) use of a selective surface on the absorber plate to cut down heat loss, 8) desired hot water temperature, and 9) insulation levels for pipes, collector, and storage. Certainly the choices of manufacturer, dealer, and installer are important, but they are beyond the scope of this study.

The cost effectiveness of a chosen system depends not only on these factors and system reliability, but on the amount of fuel used. This is a function of the volume of hot water used, the water supply temperature, the hot water temperature, the efficiency of heat transfer from conventional heater to the water, and the daily time pattern of hot water use.

This study makes a single choice for collector tilt, levels of insulation, water set temperature, and number of tanks. To diminish the number of variables, a single type of heat exchanger is used for indirect systems.

A selective surface is assumed for silicone systems, assumed absent in water systems, and an option for glycol systems. Fluid choice and area are optimized by location and fuel type, using financial criteria. The optimum system for a city is actually less than certain, due to limited knowledge of performance over time of systems of various types installed by different contractors.

The collector tilt is set equal to latitude, to the nearest 5^{o}. Computer runs for tilts from latitude to latitude plus 23^{o} showed differences of only 1-5% in fuel displaced, confirming findings by Tybout and Löf (13). Assuming that we deal with new homes and wish to keep roofs from being unsightly steep, a tilt is chosen slightly less steep than the engineering optimum.

Now substantial amounts of insulation are almost always cost effective. Insulation levels chosen here are higher than those in most existing homes, resulting in lower storage and transport losses. Insulation levels used are R-9 on the preheat tank, an average of R-10 on the smaller backup tank (R-12 on 85%, uninsulated at the flue and below the gas flame), R-3 on the 1-inch diameter pipes connecting the collector with storage, and R-8 on the back and sides of the collector.

The higher the desired hot water temperature, especially in a one-tank system, the less heat will tend to be collected, since the system will operate only when the collector, with fluid flowing through it, is hotter than the water in storage. Therefore, the set temperature T_s is chosen to be $320^{o}K$ ($116.3^{o}F$), hot enough for all uses but automatic dishwashing, for which an auxiliary heater is recommended. Use of 140^{o} water instead would require almost 40% more fuel, at an annual cost of about $60 in Table 4. The choice of hot water temperature desired has major effects on the solar

TABLE 4. Energy Effects of Water Set Temperature Choice

Assumptions:
1) 80 gallons/day of hot water use
2) R-3 insulation on 30-gallon gas water heater
3) 68°F average basement temperature
4) 60°F average water supply temperature

Description of Use	@ 116.3°F Amount ($\overline{M}$Btu)	@ 140°F Amount ($\overline{M}$Btu)
Heating for End Use	13.70	19.47
Storage Loss	2.42	3.62
Subtotal	16.12	23.09
÷ 70% efficient heat transfer	23.03	32.99
+ pilot consumption	3.33	3.33
Total Use	26.36	36.32
Seasonal Efficiency	52.0%	53.6%

fraction one could expect to achieve. A higher set temperature would yield a lower solar fraction and, in cooler climates, would yield less fuel displaced. (See Table 5.)

Two-tank systems were chosen for all locations, based on fuel displaced and capital cost. A pilot study by the Public Service Company of New Mexico (PSNM) (1) reports for April-July 1980 that their two-tank systems averaged 2.7 kWh consumption per weekday, while one-tank systems averaged 4.2 kWh. Computer runs with this model yielded similar systematic differences, but less pronounced. (See Table 6.) The PSNM study reports an average installed cost, omitting self-installed systems, of $37.58 per square foot of collector for six one-tank systems and $36.72 per square foot for ten two-tank systems. Cohen's (3) report for the Gas Research Institute uses the same cost for one- and two-tank systems. This study also estimates those capital costs to be the same. In judging this cost assumption, the reader should bear in mind a comparison between two simple tanks and one more complex tank.

Indirect systems were assumed to use a simple cross-flow heat exchanger, consisting basically of a copper tube coiled inside the preheat tank. The efficiency was assumed to be 35%. Capital costs are lower than with a counterflow exchanger, but higher than in a direct system. Danger of damage from freezing may be considerably less than in a direct system.

Collectors come in discrete sizes. The most common are 4' x 8', 4' x 10', 3' x 7', and 3' x 8'. These can form arrays with areas of 21, 24, 32, 40, 42, 48, 63, 64, and so forth square feet. This study examined chiefly four sizes to determine the optimum for each location: 3.0, 3.8, 4.5, and 6.0 m^2 (32, 41, 48, and 64 ft^2). A 2.3 m^2 collector was also examined for thermosyphon systems.

TABLE 5. Effects of Water Set Temperature on Solar Fraction

Assumptions:
1) 61 gallons/day of hot water use
2) one-tank system: 80 gallons @ R-9
3) 64°F average basement temperature
4) average water supply temperature varies by location

City	Collector Fluid	Area (m^2)	Tank Set Temp.	Energy ($\overline{M}$Btu) Operation	Fuel Displ.	Net	Conventional	Net % of Fuel Displaced
New York	glycol	3.8	140°F	.82	6.91	6.09	18.39	33
	glycol	3.8	116	.86	7.84	6.98	13.26	53
Albuquerque	glycol	5.5	129	.76	11.01	10.25	15.56	66
	glycol	5.5	116	.76	10.06	9.30	12.80	73

TABLE 6. Fuel Displacement Effects of One Tank vs. Two

Simulations for Electric Backup Heater

Assumptions as in Table 5.

City	Collector Fluid	Collector Area (m^2)	Tanks #	Tanks Set Temp.	Energy ($\overline{M}$Btu) Operation	Energy ($\overline{M}$Btu) Fuel Displ.	Energy ($\overline{M}$Btu) Net	Energy ($\overline{M}$Btu) Conventional	Net % of Fuel Displaced
New York	glycol	3.8	1	116°F	.86	7.84	6.98	13.26	53
	glycol	3.8	2	116	.97	9.00	8.03	13.26	61
Syracuse	silicone	4.5	1	116	1.09	6.67	5.58	14.40	39
	silicone	4.5	2	116	1.26	8.70	7.44	14.40	52
Albuquerque	glycol	5.5	1	116	.76	10.06	9.30	12.80	73
	silicone	3.8	2	116	1.24	10.68	9.44	12.80	74

Six types of collectors were examined to find the optimum for each city. Collectors using oil (not examined) should be similar to collectors using silicone.

A very important determinant of fuel displaced is fuel normally used, which is a function of heat transfer efficiency, tank insulation, average water supply temperature, and especially average quantity of hot water used per day. Long Island Lighting's study (7) of 632 solar/electric water heaters in their program found an average of 59 gallons/day of hot water use per home at the start of the program and 55.4 two years later. However, the amount used by households of the same size varied by a factor as large as four. Among previous simulation studies of solar hot water heating, TRW (12) assumed 85 gal/day, Schulze (11) and Bezdek (2) assumed 80 gal/day, and Cohen (3) assumed 75 gal/day. In light of the LILCO data, these appear to be toward the high end of the spectrum. Accordingly, this study assumes a steady use of 230 liters/day, corresponding to 61 gallons/day.

Of more modest importance is the timing of the use during a day. Schulze (11) assumed a use profile based on personal experience and estimation. Cohen (3) selected the MED profile used by the Southern California Gas Co. in preference to the standard RAND profile. The PSNM study in New Mexico (1) noted that owners adjusted their hot water use patterns to get better performance from their systems. In light of that information and the three published profiles, and noting that use is lumpy - showers, dishwashing, laundry - this study uses the profile in Table 7.

An initial heat transfer efficiency from gas flame to water in storage was chosen to be 75%. This is based partly on industry specifications (14) for new gas heaters, and partly on lab tests by Cohen (3) for the Daystar (70-72%) and Reliance (79-81%) gas water heaters. Efficiency should decline

TABLE 7. Daily Water Use Profile

12:00	0%	6:00	0%	12:00	3%	6:00	2%
12:30 AM	0	6:30	2	12:30 PM	0	6:30	0
1:00	0	7:00	15	1:00	0	7:00	8
1:30	0	7:30	10	1:30	0	7:30	0
2:00	0	8:00	8	2:00	8	8:00	0
2:30	0	8:30	4	2:30	0	8:30	8
3:00	0	9:00	2	3:00	0	9:00	0
3:30	0	9:30	0	3:30	0	9:30	0
4:00	0	10:00	0	4:00	0	10:00	6
4:30	0	10:30	0	4:30	6	10:30	4
5:00	0	11:00	0	5:00	8	11:00	0
5:30	0	11:30	4	5:30	2	11:30	0

over the years, but probably more slowly than a solar collector's efficiency.

The collectors modelled all have a single glass cover, copper absorber plates, and copper tubes. The tubes are 2 cm in diameter, 5 mm thick, and spaced 15 cm between centers. See Table 8 and Appendix B-3 for system specifications.

Constraints and Assumptions

The model is based on the use of average monthly weather data, rather day to day, hour-by-hour data for the 69 cities in the study. Therefore, the model is run for one day a month, the fifteenth. The temperature variation over the course of a day is estimated to follow an average pattern. Since the average change in storage temperature over one day is very small when compared to actual daily changes, the model constrains change in storage temperature in the simulation to be very small. The model assumes a constant clearness over the day, roughly comparable to constant cloud cover. It assumes a constant wind speed of 4.0 m/sec (9.0 mph). It further assumes storage tanks at a single temperature, easier to model than stratified tanks.

Due to these limitations, an adjustment is made to the output of the model to yield a more accurate estimate of how much fuel a solar system would save. The adjustment is based on McCumber's (9) comparison of actual and predicted performance, Frissora's (6) analysis of reasons for findings like McCumber's, and field results from the studies by LILCO (7) and PSNM (1).

Temperatures of water supply change during the course of a year, considerably when a small reservoir is the water source. Small variations in

TABLE 8. Physical Characteristics of Solar Hot Water Systems

Characteristic	Regular Surface	Selective Surface	All Surfaces	
Collector				
Instantaneous Efficiency*	$.73 - 6.6 \frac{\text{Watts}}{°K*m^2}$	$.73 - 3.9 \frac{\text{Watts}}{°K*m^2}$		
Total Conductance*	$7.5 \frac{\text{Watts}}{°K*m^2}$	$4.4 \frac{\text{Watts}}{°K*m^2}$		
Absorber Surface				
Emittance	.95	.10		
Absorbance			.94	
Cover Transmissivity			.88	
Heat Capacity			$5.0 \frac{\text{W-hrs}}{°K*m^2}$	
Conductance of Back and Sides			$.7 \frac{\text{Watts}}{°K*m^2}$	R- 8
Film Heat Transfer Coefficient			$1500 \frac{\text{Watts}}{°K*m^2}$	
Efficiencies				
Heat Exchanger			.35	
Heat Transfer: Electric			1.00	
Gas			.75	
Storage				
Heat Input Rate			4500 Watts	
Preheat Tank Volume: regular collectors			305 liters	R- 9
small collectors			225 liters	R- 9
Backup Tank Volume (320°K thermostat set point)			115 liters	R-10
Power Consumption				
Pump			varies: 0 or 40-90 Watts	
Controller			5 Watts	
Pipes betweeen Collector and Storage (1-inch diameter)			10 meters	R- 3
Hot Water Use (@ 320°K = 116.3°F)			230 liters/day	

* Conductance, and therefore efficiency, varies with temperatures and wind speed. The monthly average in a city will vary about 10% over a year, and the annual average will vary about 10% among cities.

the basement temperature around storage tanks are also to be expected over the year. Expected repair and maintenance costs in a system should increase with frequent freezing temperatures and also with very high operating temperatures, as pressures build and corrosion proceeds more swiftly. The model computes measures of temperature stress.

The average pattern for temperature variation over the course of a day is based on hourly newspaper reports for 45 days each during 1974 in Denver, Minneapolis, and St. Louis (4). At least twelve days each come from July, April, and a winter month. The average pattern is a smooth one with the low temperature at dawn and the high temperature 65-70% of the way from dawn to sunset, depending on the time of year. The functional form is sinusoidal from low temperature to high, and mostly linear as temperatures fall again till dawn.

The model is run for one day each month; the results are multiplied by the number of days in the month to represent the month. The model constrains the change in preheat storage temperature over 24 hours to be less than .2°C, by repeating the iteration with a new initial storage temperature until a match occurs. Since heat collection, storage losses and fuel displaced depend on the temperature of the stored water entering the collector, this procedure improves the accuracy of the model. Without this procedure, a 4° storage temperature change in one day would be multiplied by 30 for a month, suggesting a boiling or frozen storage unit.

Though the model assumes constant clearness over a day, the world is not that way. As the sun gets higher in the sky, it traverses less atmosphere, and so less light is scattered back into space. More important, cloud cover changes. The model, at each half hour, assumes constant substantial fractions of both direct and diffuse radiation. But Frissora observes (6): "A more probable occurrence is that the direct beam light, plus some of the diffuse, usually impinges on the collector for a portion of the hour, and only diffuse light at much lower intensity strikes the collector for the rest of the hour. ... Under these latter conditions ... flat plate collectors usually shut down and cool off."

Wind speeds are not constant, but do not show systematic variation over the course of a day (10). A brief check of average monthly wind speeds over three years in five scattered cities suggested small systematic seasonal variations, similar in size to the variation in average annual wind speed among the cities: 7.7 mph to 10.4 mph. Duffie (5) gives a formula for conductance of a collector, used in simplified form by this model, as a function of temperatures of the air and collector and of the wind speed. The differences in heat loss from 8 mph and 10 mph winds is on the order of 4%, but between 8 mph and 0 mph it is near 50%. This model assumes a constant wind speed of 9 mph, for a minor error in output.

The model estimates water supply temperature, which varies each month in the 69 cities, based on their average monthly and annual temperatures and using a lag structure. Cohen (3) reports monthly water supply temperatures ranging, for example, from 38°F to 57° in Madison and from 68 to 83 in Miami. Similarly, this study's model estimates supply temperatures ranging from 36°F to 55° in Madison and from 72° to 78° in Miami, with corresponding ranges in 67 other cities. Since it takes twice as much energy to heat water from 36° to 116 as it does from 76 to 116, one certainly expects the demand for energy to heat hot water to be much higher in Madison than in Miami, as the model indeed projects.

Both hot and cold temperature stress indices are computed. The cold stress index is based on how much time is spent below freezing and how far below, using average monthly low temperatures in a city. The heat stress index is a function of collector choice as well as climate. It is designed to indicate the increased pace of corrosive chemical reactions at higher temperatures, and the stresses of vapor pressure and unequal expansion of different materials. The index is based on how long and how far above an arbitrary threshold of 340°K (152°F) the collector temperature stays.

The results from the engineering model are adjusted downward before they are used elsewhere; estimated fuel displaced is 85% of that given by the engineering model. The numbers in Tables 5 and 6 have already been so adjusted. The most important reason for the adjustment, alternating clouds and sunshine, was already cited from Frissora. McCumber (9) compares predicted and actual energy gain for seven collectors in commercial installations, six of them flat plate collectors. He found they produced 5, 10, 27, 28, 31, and 46% less energy during August than predicted by using Eq. 4 above. He says that standard equation is inadequate for modelling dynamic effects, echoing some of Frissora's concerns. Frissora (6) draws attention to the neglect by many programs of transient effects of alternating sun and cloud, cooling effects of rain, convection heat losses due to winds, heat losses from pipes connecting collector with storage, heat losses from storage tanks, losses due to a heat exchanger, the dependence of heat transfer coefficients (U_c) on the ambient air temperature, and the questionable practice of using a daily water use profile having substantial loads each hour of the day. This model deals effectively with the last five or six problems mentioned.

LILCO (7) reports a 44% average solar fraction on Long Island with a 40 ft^2 collector, one tank, and 140° set temperature. PSNM (1) reports a 55% solar fraction the first year and just over 70% average (8) thereafter around Albuquerque. In light of McCumber's findings, the results of LILCO and PSNM, and the many reasons cited by Frissora, of which this model short-changes only the most important single one, multiplications by .85 yields solar fractions pretty consistent with actual field results. Compare 44% in New York and 70% in Albuquerque with the numbers in Tables 5 and 6: 33-53% and 66-74% respectively, where the LILCO data are for single-tank systems only, most with 140° storage temperature.

III. THE FINANCE MODEL

Features of the Model

Many features of the model merit discussion. Some involve data inputs. The model concentrates on present value of costs and savings each year. It includes tax savings from interest deductions and from both federal and state tax credits. A uniform rate is used for general inflation, but provision is made for a change in the real inflation rate for the fuel displaced. Initial gas and electric prices come from a survey of more than 115 utilities in 69 cities in 46 states. Investment costs for types of solar domestic hot water (DHW) systems are based chiefly on a telephone survey of 12 retail dealers/installers in 9 states.

Some features involve treatment of estimated costs over time. Real price growth for electricity and gas begins from a local base and rises toward an escalating national average; that is, relative regional differences diminish over time. Operating energy, initially given by the engineering model, increases very slowly over time. Fuel displaced, after the first two years, also decreases slowly over time, as the solar system is expected to decrease in efficiency more quickly than a conventional heater does. As explained in the previous section, initial gross fuel displaced is estimated to be 85% of the output projected from the engineering model. The treatment of expected maintenance and repair costs is the most complex and the most uncertain.

The model uses a positive net present value criterion for a decision whether to invest in solar DHW, with a 20-year horizon. The investment is assumed financed by a loan. The model considers costs of capital, operation, and maintenance and repairs, as well as savings on fuel and taxes.

Tax considerations are crucial. The present value of tax savings can be more than 90% of the initial investment cost! Five types of tax effects are considered. Most obvious are federal and state tax credits. In early 1984, there are credits of varying sizes in 27 states and a 40% federal tax credit. Next in importance is the value of itemized interest deductions on tax returns, stemming from the loan used to buy the system. Marginal tax rates are used. Use of savings would be equivalent to using a loan with a very long term. Some states charge sales tax on solar DHW system sales and some do not. A tax similar to a sales tax is levied on fuel sales in almost all places. Finally, most places exempt solar DHW systems from property tax; it is assumed here that all do. See Appendix B-2 for a complete list of numerical tax data used.

Since natural gas prices are undergoing decontrol, this study expects residential gas prices to reach parity with home heating oil prices not long after decontrol is "complete." Then projected price increases are slower. A similar, but less pronounced, effect is projected for electric prices, as major rate increases now occur for some utilities engaged in large building programs initiated in the early 1970's. With demand for electricity now growing quite slowly due to high prices, little new plans to build are expected, so that the cost of electricity should rise quite slowly in the 1990's as current plant is depreciated. So the model allows for fuel prices to increase at one rate for a few years, and at a different rate thereafter.

Gas and electric price data were gathered chiefly by letter and also by telephone, from mid-November 1983 to mid-February 1984. All responding utilities supplied rate schedules for residential customers, and most gave average use figures and applicable tax rates. A few supplied other very helpful information. Average and marginal (customer standpoint) price data were prepared from these for a customer with average use levels. In addition, the marginal price was calculated for an all-electric customer using twice the company average. See Appendix B-1 for a complete list of fuel price data by city.

Gas is sold both by volume and by heat content. At low altitudes, 1.0 $\overline{M}$Btu ≐ 1.0 mcf, but at higher elevations 1 mcf contains less than 1 $\overline{M}$Btu of heat. In mountain states, prices in \$/mcf were converted to \$/$\overline{M}$Btu based on conversion factors supplied by two mountain state utilities. Gas utilities generally employ seasonal rates and a customer charge with a flat rate. Declining rate block structures are the most common type among electric utilities, with seasonal structures the general rule. Seasonal structures were converted to single prices by assuming constant electric use over the year and some increased gas use in the winter.

A survey of twelve solar dealers is the basis for estimated costs of systems used in this study. See the bibliography for a list of the dealers. Costs for a system of given collector area vary depending on the size and quality of the system, including any use of anti-freeze fluid, efficiency of the heat exchanger, use of a selective surface, and other features. But almost as significant is geographic variation. The same system sells for 16% more in Boston than it does in Reno. A third city, with intermediate economic prospects according to the results of this study, sells it for an intermediate price. A rough rule of thumb is that an installed system costs \$1000-1500 plus \$25-45 per square foot. Costs used in this study reflect prices probably available in a high volume solar installation area, and understate those in a low volume area. I acquired no data for thermosyphon systems, but relied on the numbers used by Cohen (1). Extrapolations and interpolations were also necessary. About half the dealers called from 1982 yellow page listings in 16 cities had disconnected phones, which suggests that dealer warranties are less valuable than manufacturer ones.

Regional fuel price differences are projected to diminish over time. In natural gas, this means an assumption that consumer price increases will be due primarily to increases in wellhead price, and only slightly to distribution and administrative real cost growth. In electricity, for example, an area with fully developed cheap hydro power may build expensive nuclear plants to meet growing demand, while areas using expensive oil will build no new plants and switch to cheaper fuels. The mechanism for raising fuel price is to raise the real price locally each year by the increase of the geometric mean of initial local and national average prices.

The very slow increase in operating energy over time reflects partly that a pump must work harder to push fluid through fouled pipes. More important, a lower average storage temperature over the years, as energy collected declines, means the pump will come on earlier and shut off later.

In the first year or two, fuel displaced should be significantly less, as equipment and installation problems are discovered and corrected. One result is down time and less fuel displaced. In New Mexico, systems which averaged a 55% solar fraction the first year now average near 70% (2). Later, problems such as fading black paint on the absorber, a pitted glass cover on the collector, worn insulation on pipes and storage, and fouled and corroded pipes, should result in less energy collected and more of what is collected being lost. Fouled pipes and perhaps graying surfaces can be affected by initial choices. Worn insulation and old fluid can be replaced, at a cost. The model's computations reflect these considerations.

Expected maintenance and repair costs reflect the following thoughts. 1) Costs should be higher in the first year or two, as "bugs" are eliminated.

2) Costs should rise slowly over time, as wear and corrosion proceed. 3) Parts such as pumps, fluids, and sensors may need to be replaced at regular intervals. 4) Costs should be higher in areas with frequent sub-freezing temperatures and 5) in systems with frequent very high operating temperatures and more stagnation time. 6) The choice of a collector fluid can have a large bearing on these costs.

The computational mechanism uses indices of heat and cold stress, and estimated responses of fluids to these effects. Responses are uncertain but the result should be more accurate than assuming no such effect. The origin of the heat and cold stress indices for each place and system is discussed in the "Constraints and Assumptions" section of the engineering model description. Appendix B-3 gives the estimated fluid responses. The reader should consult Hodges (3) for results of lab tests on glycol, oil, and silicone fluids with respect to high and low temperatures, solvent properties, fluid change intervals, and differences in investment cost.

Experience has shown a fairly high incidence of system failures. Freezing generally requires replacing the collectors, roughly $1,000. Hooks (4) reports six of twenty drainback units froze the first winter and 6 more the following winter in a pilot study on Long Island. This led to a change in design by the manufacturer, which seems to have solved the problem. Albright (5) reports 20 of 29 systems in a New Mexico study experienced problems leading to down time during the first year, including 10 leaks and 6 freezeups. Chopra (6) reports freezing in a third of 45 systems studied through June 1978 and a fifth of 65 systems the following year. The reports by Albright and Chopra include freezing frequencies over 15% for glycol systems. Over half the freezeups reported were due to installation error. On the other side are January 1984 reports from two Denver solar dealers (7) that, with the coldest December on record there, only 0 of 70 and 10 of 2,500 water drainback (!) systems froze that month, among ones that they installed.

I draw the conclusions 1) that freezing is a substantial risk, which can be reduced 2) by fluid choice, 3) by a better designed (or redesigned) system, and 4) by one which is installed by an experienced contractor. My algorithms assume a risk of freeze damage lower than suggested by the three cited reports based on "first in the town" installations in the late 1970's, but higher than suggested by reports of dealers who sell a reliable field-tested product they install correctly every time in the 1980's. They also reflect a better than even chance that damage due to "bugs" will be repaired under warranty at little or no cost to the homeowner. Costs may be higher than projected in a low volume area and lower in a high volume area, due to the experienced installer effect.

Formal Description of the Model

The financial program operates in three stages: initial, annual, and final. Comparing a solar domestic hot water (DHW) system with a gas or electric backup to a non-solar DHW system, it calculates six types of savings or costs: capital costs, operating costs, maintenance and repair costs, tax savings, fuel savings, and net savings. To simplify this exposition, I assume here 1) state and federal income taxes due are large enough so the full tax credits can be used the first year, 2) the investment in the system is financed by a loan with 0% down payment, and 3) deductions claimed for interest paid do not change the taxpayer's marginal tax brackets.

Initially the program calculates an annual loan payment and the federal and state tax credits available.

(1) $C_{k,0} = I * \frac{r}{1-(1+r)^{-T}}$ Ex. $\$341.65 = \$2400(\frac{.13}{1 - 1.13^{-20}})$

where I is the initial investment, r the interest rate on the loan, T the loan's term in years, and $C_{k,0}$ the annual loan payment.

(2) $D_f = d_f * I = .40\ I$ Ex. $960 = .40 ($2400)

(3) $D_s = d_s * I$ Ex. $360 = .15 ($2400) (New York)

where d_f and d_s are the federal and state tax credit rates, I the investment, and D_f and D_s the tax credits.

(4) $C_{k,t} = C_{k,0}$ if $t \leq T$; otherwise $C_{k,t} = \$0$.

Each year's capital cost $C_{k,t}$ equals the annual loan payment (sum of principal and interest payments), unless the term T of the loan is already finished.

Real maintenance and repair costs follow a U-shaped curve over time. Costs are higher (and energy collected lower) in the first year as "bugs" are eliminated from the system. These costs also depend on heat and cold stress, and the collector fluid's susceptibility to them.

(5a) for t=1, $C^*_{m,t} = .02 * I * (1 + .005\ L * H_c + .00035\ M * F_c)$

Ex. $77.24 = .02 ($2400) (1 + .005 [2*7.9] + .00035 [1*1515])

(5b) for t>1, $C^*_{m,t} = .01 * I * (1 + .0025\ L * H_c + .00015\ M * F_c) * e^{.02t}$

Ex. $\$35.68 = .01*\$2400*(1 + .0025\ [2*7.9] + .00015\ [1*1515]) * e^{.02*8}$

$C^*_{m,t}$ is the expected real maintenance cost in year t, I is the initial investment, and t is the year. H_c and F_c are indices of heat stress and cold stress for a particular place. L and M are indices of a fluid's resistance to heat effects and to freezing damage respectively.

(6) $C_{m,t} = C^*_{m,t} * (1 + i)^{t-.5}$ Ex. $\$59.27 = \$35.68 * (1.07)^{8-.5}$

$C_{m,t}$ is the current dollar cost of expected mainteance and repairs, $C^*_{m,t}$ is the constant dollar cost, i is the general inflation rate, and t is the year.

Operating cost depends on the energy needed to operate pumps part of the time and controls all of the time, and on the price of that energy. Pump energy needed comes from the engineering model. The price of electricity to operate rises at a rate based on general inflation, projected real electric price inflation, and local and national prices for electricity.

(7) $P_{e,t,c} = (P_{e,0,c} - P_{e,0,n}) + (P_{e,0,c} * P_{e,0,n})^{.5} * (1 + i + i_e)^{t-.5}$

Ex. $(\frac{\$}{\overline{M}Btu})\ 71.85 = (39.90 - 19.56) + (39.90*19.56)^{.5} * (1.07+.015)^{8-.5}$

$P_{e,t,c}$ is the projected price of electricity in year t in city c. $P_{e,0,c}$ and $P_{e,0,n}$ are the initial local and national prices of electricity. The general inflation rate is i , the electric real price inflation rate is

i_e , and t is the year. Two notes: 1) The example is for New York. 2) If $P_{e,t,c}$ is less than $P_{e,0,c}$, then $P_{e,0,c}$ is used for $P_{e,t,c}$ that year.

(8) $E_{op,t} = E_{op,0} * e^{.004t}$ <u>Ex</u>. 1.004 $\bar{M}$Btu = .972 $\bar{M}$Btu * $e^{.004*8}$

$E_{op,t}$ is the expected operating energy used in year t, and $E_{op,0}$ is the operating energy computed from the engineering model, for the particular collector design and location.

(9) $C_{op,t} = E_{op,t} * P_{e,t,c} * (1 + v_e)$ <u>Ex</u>. \$82.49 = 1.004 * \$71.85 * 1.1435

$C_{op,t}$ is the current dollar cost of expected operating energy in year t in a given place. $E_{op,t}$ and $P_{e,t,c}$ come from Eqs. 8 and 7. The tax rate on electricity sales is v_e (14.35% in New York City).

Fuel savings are similarly calculated in three steps. The amount of fuel saved is calculated, the current price of fuel is computed, and their product plus sales tax is the fuel saving.

<u>Examples (in $\bar{M}$Btu)</u>

(10a) if t=1, then $E_{f,t} = E_{f,0} * (.9 - .03*[L+M])$ 9.82= 12.12(.9-.03[2+1])

(10b) if t=2, then $E_{f,t} = E_{f,0} *(.98 - .01*[L+M])$ 11.51=12.12(.98-.01[2+1])

(10c) if t>2, $E_{f,t} = E_{f,0} * e^{-.005t} *(1+.01 L*H_c)$ 11.57=12.12 $e^{-.04}$(1.158)

$E_{f,t}$ is year t's expected amount of fuel displaced and $E_{f,0}$ is the adjusted (multiplied by .85) initial fuel displacement from the engineering program. L and M index fluid susceptibility to heat and cold stress. H_c is the heat stress for a particular collector and place (New York in Example 10c).

(11a) if $t \leq t^*$, then $P_{f,t,c} = P_{f,0,c} + (-1 + [1+i+i_{f1}]^{t-.5}) * (P_{f,0,c} * P_{f,0,n})^{.5}$

Ex. $\left(\frac{\$}{\bar{M}Btu}\right)$ $8.73 = 7.12 + (-1+[1+.07+.09]^{2-.5}) * (7.12 * 5.82)^{.5}$

(11b) if $t > t^*$, then $P_{f,t,c} =$

$$P_{f,0,c} + (P_{f,0,c} * P_{f,0,n})^{.5} * (-1 + [1+i+i_{f1}]^{t^*} * [1+i+i_{f2}]^{t-t^*-.5})$$

Ex. $\left(\frac{\$}{\bar{M}Btu}\right)$ $11.98 = 7.12 + (7.12*5.82)^{.5} * (-1 + 1.16^3 * 1.09^{8-3-.5})$

Real fuel prices may rise at rate i_{f1} for t^* years and at rate i_{f2} thereafter. $P_{f,t,c}$ is the projected local current dollar price of the fuel displaced in year t. $P_{f,0,c}$ is the local fuel price in the winter 1983-84. $P_{f,0,n}$ is the average fuel price for the 69 cities found in the survey that winter. The general inflation rate is i .

(12) $S_{f,t} = E_{f,t} * P_{f,t,c} * (1 + v_f)$ Ex. \$158.50 = 11.57*\$11.98*1.1435

$S_{f,t}$ is the projected value of the fuel displaced in year t, reckoned in current dollars. $E_{f,t}$ and $P_{f,t,c}$ are the amount and price of the fuel displaced in year t in location c , from Eqs. 10 and 11. The tax rate on fuel sales is v_f .

The tax saving has four components: values of state and federal income tax deductions for interest paid, and the values of federal and state tax credits. Most states exempt solar water heating systems from property taxes, so no property taxes are deducted from the sum of the other four. In some states, a sales tax is charged on solar equipment purchases.

First interest paid is calculated.

(13) $J_t = K_t * r$ $\quad$ Ex. \$271.83=\$2091(.13) (t=8, I=\$2400)

J_t is the interest paid in year t, K_t (see Eq. 22) is the remaining principal at the start of year t, and r is the interest rate on the loan.

Then the value of the tax deductions is calculated.

(14) $S_{sr,t} = J_t * x_s$ $\quad$ Ex. \$38.06 = \$272 (.14) (still NYC)

(15) $S_{fr,t} = J_t * x_f * (1 - x_s)$ $\quad$ Ex. \$77.15 = \$272 (.33) (1-.14)

The marginal federal and state tax rates for the solar owner/taxpayer are x_f and x_s. J_t (Eq. 13) is the interest paid that year. $S_{fr,t}$ and $S_{sr,t}$ are the tax savings at the federal and state levels, respectively, for the interest deductions in year t.

Next comes figuring the tax credits.

(16) $S_{sd,t} = D_s$ if t=1, but = \$0 otherwise. $\quad$ Ex. D_s = \$360

(17) $S_{fd,t} = D_f$ if t=1, but = \$0 otherwise. $\quad$ Ex. D_f = \$960

$S_{sd,t}$ and $S_{fd,t}$ are the savings from state and federal tax credits respectively. D_s and D_f are the available credits (Eqs. 2 and 3).

The total tax savings $S_{tx,t}$ is computed.

(18) $S_{tx,t} = S_{sr,t} + S_{fr,t} + S_{sd,t} + S_{fd,t}$

Ex. \$115.21 = \$ 38.06 + \$77.15 + \$ 0 + \$ 0

Some states charge a sales tax on the sale of a solar DHW system. In them, in the first year, the tax saving is reduced by the sales tax, at rate v_s, on the purchase of a system costing I.

(18a) $S_{tx,1} = S_{tx,t} - v_s * I$

The net saving $S_{n,t}$ is the sum of five components: costs for capital, maintenance and repairs, and operation, and savings in fuel displaced and on taxes.

(19) $S_{n,t} = S_{f,t} + S_{tx,t} - C_{k,t} - C_{m,t} - C_{op,t}$

Ex. -\$209.70 = \$(158.50 + 115.21 - 341.65 - 59.27 - 82.49)

The terms for fuel saving, tax saving, capital cost, maintenance cost, and operating cost come from respectively Eqs. 12, 18 (18a), 4 (1), 6, and 9.

Each year the present value of net saving, fuel saving, tax saving, capital cost, maintenance and repair cost, and operating cost are calculated, using the present value factor V_t for year t, using discount rate r.

(20) $V_t = (1+r)^{-t}$ Ex. $.376 = 1.13^{-8}$

(21) $W_{n,t} = V_t * S_{n,t}$ Ex. -\$78.88 = .376(-\$209.70)

$W_{n,t}$ is the present value of net saving in year t, $S_{n,t}$ (Eq. 19) is the net saving then, and V_t is the present value factor for year t. Other $W_{..,t}$ are similarly defined.

The program keeps a running total of the W's: present values of the savings and costs.

The last step in the program is to compute the loan's remaining principal for the coming year.

(22) $K_{t+1} = K_t + J_t - C_{k,0}$ if $t<T$, but = \$0 otherwise.

Ex. \$2021.18 = \$ 2091 + \$ 271.83 - \$341.65

The principal at the start of the year, K_t, the interest J_t, and the annual payment C_k come from Eqs. 22, 13, and 1. Of course, if t=1, then K_t=I.

At the end of the 20 year simulation period, the totals for energy delivered and for each kind of saving or cost are printed. Annualized costs and savings can then be computed. The annualized cost factor is

(23) $m = \frac{r}{1-(1+r)^{-20}}$ Ex. $.1423 = \frac{.13}{1-1.13^{-20}}$

where r is the discount (loan) rate and m is the annualizing factor. Then the annualized net saving L_n can be found.

(24) $L_n = m * \sum_{t=1}^{20} W_{n,t}$ Ex. -\$83.53 = .1423(-\$587) (NYC)

where $W_{n,t}$ is the present value of net savings in year t, from Eq. 21. L_k, L_m, L_{op}, L_f, and L_{tx} can be similarly defined.

Risk considerations aside, a positive net present value, equivalent to a positive L_n, indicates the investment in a solar DHW system should be undertaken.

Base Case Economic Assumptions

Some important financial parameters are givens, some are fixed at the time of purchase, and some involve crystal ball gazing. The federal and state tax structures, including tax credits, are fixed now and are expected to continue as is, except perhaps for solar tax credits, for the forseeable future. Tax effects of a solar decision depend on a purchaser's income. The value of the credits depends only on the next one to four years' income, but the value of deductions depends on income farther in the future. The cost of the system, the method of finance, any down payment, and the rate of interest or discount are decided at the time of purchase. Predicting future performance involves some crystal ball gazing. Predicting fuel price increases has a history of confounding the experts, but well-informed projections are better than pure guesswork. Predicting inflation is in the same category. Predicting maintenance and repair costs over twenty years for systems, none of which has been in use over ten years, is guesswork where information has some value.

This study assumes constant marginal tax rates, perhaps indexed for inflation, and the continued deductibility of interest expenses over twenty years. Tax data were gathered for incomes of $45,000, $24,000 and $16,000. The base case considers a moderately rich person with $45,000 in taxable income. The study considers two cases for tax credits. Either they continue as is for ten years, or they expire within five years.

The installed cost of a system depends on size and type of system, and on locale, installer, warranties, and new or retrofit installation, which four are beyond the scope of this study. This study assumes the installation is in a new home, but an analysis for retrofits would be only a little different, chiefly in the terms of a loan and orientation of a collector. Table 9 gives the estimated installation costs for the systems used in this study.

The base case assumes that the system is financed by a loan at 13% interest, with no down payment, over a 20-year period, as part of a new-home mortgage. The period is close to both the expected system life and the

TABLE 9. Installed System Costs

System Type	Area 2.3m^2	3.0m^2	3.8m^2	4.5m^2	6.0m^2
thermosyphon	\$2000	\$2150	\$2300	\$2450	\$2750
draindown water		2300	2550	2800	3300
drainback water		2600	2800	3000	3400
drainback water/glycol: regular surface		2650	2850	3050	3450
drainback water/glycol: selective surface		2800	3000	3200	3600
drainback silicone		3000	3250	3550	4200

typical term of a mortgage. The real interest rate is extremely high by historical standards, but is typical of mortage rates and good terms on home improvement loans in early 1984.

The behavior of fuel displacement, operating energy, and maintenance and repair costs has been discussed at length in a preceding section. The first two interact with fuel price increases to yield costs and savings. This study uses a general inflation rate of 7% per year for 20 years, very slightly above the average compound inflation rate over the previous 20 years. This leaves a projected 6% real interest rate in the base case.

Within the framework discussed in the previous section, the base case assumes the residential price of natural gas will rise to meet that of home heating oil in three years. The real price of heating oil is assumed unchanged after 3 years. The estimated heating oil price is \$8.26/M̄Btu (8) in March 1984 and the average gas price is \$6.37/M̄Btu in February 1984. The rounded result is 9% a year real marginal price increase for natural gas for three years. The rate should slow considerably then. A rate of real price increase of 2% a year is assumed thereafter, based on a continued decline in reserves. These rates are slightly greater than the American Gas Association's projections for the increase in wellhead prices over this period (9).

The price of electricity should rise at very different rates in different places in the next several years, depending on growth in demand relative to plant under construction. But this study will not attempt to discriminate between different rates of local price increases. It assumes real electric price inflation of 3% a year for three years and 1.2% a year thereafter, or simply 1.5% a year for electricity as an operating fuel.

The choice of which gas or electric price to use is significant: average or marginal, general or all-electric. Since the customer must pay the

TABLE 10. Base Case Economic Assumptions

General Inflation	7% / year
Real Price Inflation	
Natural Gas	9% / year for 3 years, 2%/ year thereafter
Electricity	3% / year for 3 years, 1.2%/ year thereafter
Solar DHW Systems Purchase	0% / year
Maintenance and Repair	0% / year
Financing Arrangement	
Loan	13% interest 0% down payment annual payments 20 year term
Taxes	
Taxable Income	$45,000/year for 20 years
U.S. Tax Credit Rate	40% of purchase
State Tax Credit Rate	varies; see Appendix B
U.S. Marginal Tax Rate	33%
State Marginal Tax Rate	varies: see Appendix B
Prices	
Solar DHW System	varies; see Table 9
Natural Gas Initial	marginal
69 city average	$5.82/$\overline{M}$Btu
local	varies; see Appendix B
Electric Initial	marginal
Regular	
69 city average	$19.56/$\overline{M}$Btu
local	varies; see Appendix B
All-Electric	
69 city average	$17.90/$\overline{M}$Btu
local	varies; see Appendix B

customer charge whether or not s/he has a solar system, it seems that the customer's marginal cost is the more logical one to use. Fuel saved is priced at the customer's marginal cost, and operating electricity is charged at a customer's marginal cost. Complications arise when the customer has more than one marginal cost, as with time-of-day pricing or controlled water heaters. A customer's marginal cost depends on the current rate structure, but at present there is some movement to revise rate structures from the declining block to the flat rate or inverted structure. Still, the base case uses marginal cost as the fuel price.

Recalling the discussion in the introduction, in the electric/solar comparison, the comparison is probably made for an all-electric home, for which a special rate may be available, reflecting the favorable effect of such homes on an electric utility's load factor. Therefore, such a rate, if available, is used for the marginal fuel price in solar/electric comparisons. Finally, I note that the customer's marginal cost may be very different from the company's, and the company may have quite different short run and long run marginal costs.

Projection of maintenance costs is detailed in previous sections.

Following the discussion in the introduction, the installed cost of a solar DHW system is projected in the base case to neither increase nor decrease over time. See the concluding chapter for further discussion.

Typical Model Output

Table 11 which follows is for an optimum solar/gas water heating system in New York City, having a 3.8 m^2 collector with selective surface and using glycol/water fluid. Assumptions are given in Tables 7-10 and in Appendix B.

TABLE 11. Sample Output: Annual Costs and Savings with a Solar Hot Water System (New York City - 1984)

Backup Fuel:	Natural Gas	Taxable Income	$45000	Installed System Cost	$3000
Fuel Heat Transfer Efficiency: 75% initially		US Marginal Tax Rate	33%	Inflation Rate	7%/yr
		NY Marginal Tax Rate	14%	Gas Real Price Inflation Rate: 9%/yr for 3 years, then 2%/yr	
Financed by a 20-year loan at 13% interest, $0 down		US Tax Credit	$ 1200		
		NY Tax Credit	$ 450	Electric Real Price Inflation: 1.5%/yr	

Year	Principal of Loan	Interest on Loan	Fuel Displaced (MBtu)	Costs: Operation	Costs: Maintenance	Costs: Capital	Savings: Fuel	Savings: Tax	Savings: Net	Savings: PV of Net	Savings: Sum of Net PV
1	$3000	$390	9.72	$55	$100	$427	$ 85	$ 1695	$ 1198	$ 1060	$ 1060
2	2963	385	11.40	58	44	427	114	163	- 252	- 197	862
3	2921	380	11.79	61	48	427	135	161	- 240	- 166	696
4	2874	374	11.72	64	52	427	150	158	- 235	- 144	552
5	2820	367	11.66	67	57	427	162	155	- 235	- 127	425
6	2760	359	11.59	71	62	427	174	152	- 234	- 113	312
7	2692	350	11.52	75	68	427	188	148	- 234	- 100	213
8	2614	340	11.46	80	74	427	203	144	- 234	- 88	125
9	2527	329	11.39	85	81	427	219	139	- 234	- 78	47
10	2429	316	11.32	90	88	427	237	134	- 235	- 69	- 23
11	2317	301	11.26	96	96	427	256	128	- 236	- 62	- 84
12	2192	285	11.19	102	105	427	276	121	- 237	- 55	- 139
13	2049	266	11.13	109	115	427	299	113	- 239	- 49	- 188
14	1889	246	11.06	116	125	427	323	104	- 242	- 44	- 231
15	1707	222	11.00	124	137	427	349	94	- 245	- 39	- 271
16	1502	195	10.93	133	150	427	377	83	- 249	- 35	- 306
17	1270	165	10.87	142	163	427	408	70	- 254	- 32	- 338
18	1008	131	10.81	152	178	427	442	56	- 260	- 29	- 366
19	712	93	10.74	163	195	427	478	39	- 268	- 26	- 392
20	378	49	10.68	175	212	427	517	21	- 277	- 24	- 415

IV. RESULTS

Choosing an Optimum System for a Location

An optimum size and type of system was estimated for each city, giving two optima, one solar/electric and one solar/gas. Throughout the process, the base engineering and economic assumptions specified previously were used, with a single exception. Constraints were placed on the types of systems considered in a location, depending on the expected frequency of freezing temperatures there. The system with the highest net present value for a city was chosen the optimum, a choice very sensitive to expected maintenance and repair costs for that type (and size) in that location. Considerable uncertainty exists about what these costs will be; the optimal type of system is correspondingly less than certain.

The assumptions and inputs are in Tables 7-10 and in Appendix B. The income tax rates and water use levels are assumed constant over 20 years. The exception mentioned above is that the optimizing process assumed fuel displaced was 75% of that projected by the engineering model, a figure later raised to 85% to better approximate actual results in New Mexico and on Long Island.

Three constraints were made in the systems considered. First, thermosyphon systems were examined only in those eleven cities where freezing temperatures are rare, deduced from a lowest monthly average minimum temperature of 4°C or higher. Second, direct systems were considered only where nighttime freezing temperatures in winter are not the norm, based on a lowest monthly average minimum temperature of -1°C or higher. This criterion yields thirty cities, but excludes Albuquerque, Denver, Reno, and Tucson. Third, capital intensive anti-freeze systems were not examined where thermosyphon systems were examined.

Where they were examined, thermosyphon systems were always the most cost effective. However, they may not be chosen for aesthetic or other reasons. (1) Direct draindown water systems were the choice almost everywhere they were considered but thermosyphons were not. Silicone systems were chosen more frequently than glycol systems in the remaining cities, especially in very cold places and very hot ones. Glycol systems were the choice mainly in Appalachia, the Atlantic seaboard states, and the "border states." Indirect drainback water systems were not the first choice in any location.

Tax benefits repaid 57-94% of capital costs, depending on location, so the results for choice of system type are sensitive to the model's assumptions about maintenance and repair costs. Oversized systems gather too much heat, with high operating temperatures and heat stress. Thus maintenance costs, as an annualized percent of investment cost, tend to be lower for smaller sized systems. As a result of using the choice criterion of highest expected NPV, the expected annualized maintenance cost for an optimum system ranged from 2.1 to 3.4% of investment everywhere but El Paso and Las Vegas, where it was under 4.4%. (For reference, an assumption that maintenance costs annually are 2% of investment, escalated at the general inflation rate, yields an annualized cost of 3.4% of investment.) Expected maintenance and repair costs for non-optimum systems were in many cases far higher. (2) The analysis here outlined can certainly benefit from modification as maintenance and repair expense experience over long periods accumulates for solar DHW systems.

By far the most common optimum collector size for solar/electric systems was 41 ft^2, but 32 ft^2 systems were equally well represented among optimum solar/gas systems. A 64 ft^2 collector was optimum for solar/electric systems in only four cities, and optimum for solar/gas systems nowhere. Of course, with above average hot water use per day, a larger size collector would be recommended. Noting that each additional ft^2 of collector gathers less heat than the one before it as the gross solar fraction approaches 100%, the greater cost of a larger collector can be justified as the value of the fuel displaced rises. In general, a larger size is optimum with electricity than with gas, since electricity is much more expensive than gas in the cities surveyed.

Factors Affecting Solar Domestic Hot Water Feasibility

Both geographic and non-geographic factors influence the economics of solar DHW heating. The level of real interest rates is quite important. So is the initial cost of a system, for a given quality. Which fuel solar energy is seen to compete against is crucial to decisions. Operation and maintenance costs are also quite significant.

Three geographies are important. Obviously, the geography of climate - sunshine and temperature - largely determines the amount of fuel displaced. The geography of fuel prices is also important. But most important, in view of "high" capital costs, is the geography of taxes. Tax benefits repay about 57% of capital costs in Connecticut, but 94% in neighboring Massachusetts, for the base case income.

Real interest rates in spring 1984 for home investments are about 8%, far above normal historical rates near 3%. The result can be viewed as a strong discounting of future costs and savings, especially discounting future fuel savings. Real interest rates in the study are projected to be 6%, due to an increase in inflation. Real interest rates of only 3% would double the number of places where solar DHW is projected to compete successfully against natural gas, and make it compete successfully against electricity in a third of the places it now does not.

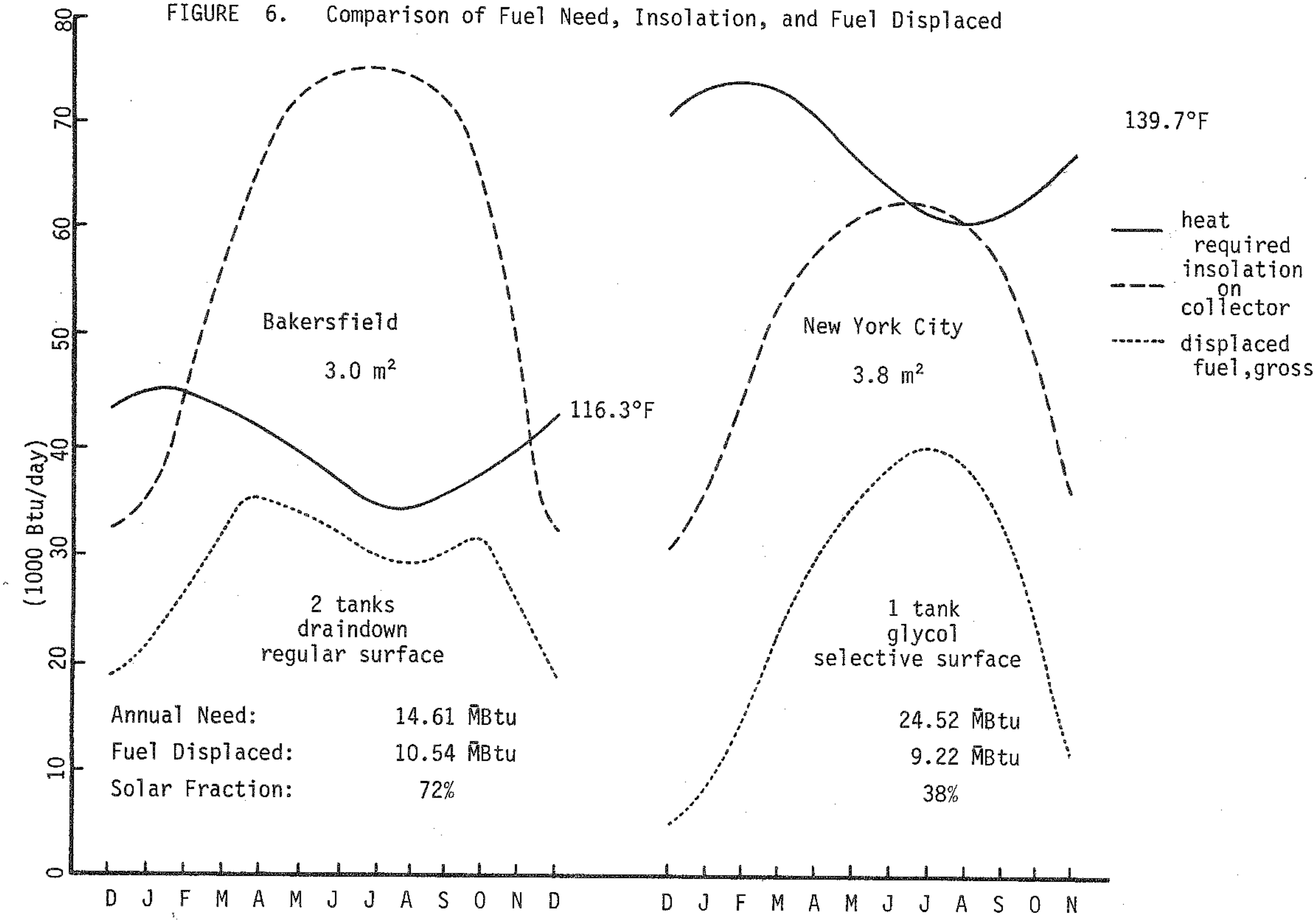
As was observed in previous sections, capital costs for solar systems have apparently not declined in the last decade. Cohen (3) finds that in all four places they examined, the installed cost of every solar/gas system was higher than the projected life-cycle cost of a gas-only system. With recent gas price increases, this is no longer true for the thermosyphon systems in that analysis, but remains true for other types and locations in the country. Cohen (4) advocates a "thrust should be to reduce the system installed cost as opposed to reducing the energy consumption," a statement with which this author agrees.

This study repeats findings by earlier studies that solar water heating is far more competitive against electricity than against gas.

This study finds projected annualized maintenance costs to be 15-30% of annualized capital costs, averaging 18%. Operating costs average 7% of capital costs, ranging from 1-3% for thermosyphons, to 17%. Operating energy averages 9% of gross electric energy displaced and 7% of gross gas energy displaced.

The effects of sunshine differences due to different latitudes and degrees of cloud cover are much as one would expect. But the role of temperature differences often runs counter to intuition. Though heat loss from a collector is greater in cold climates, this can be cut greatly by using a selective surface on the absorber (for a somewhat greater installed cost). More important, the heat needed to raise very cold water to 116°F is far more than that needed to raise warm water to that temperature. A result is that a 64 ft^2 collector in Duluth gathers more than enough energy to supply

FIGURE 6. Comparison of Fuel Need, Insolation, and Fuel Displaced



all of Miami's hot water heat need. See Figure 6 for a comparison of a warm and sunny city with a cool and cloudy one. Fuel displaced in Bakersfield in the warmer months is limited to 85% of the fuel needed. In New York (in this example using sub-optimal storage), the amount of fuel displaced is not thus limited in even a single month. Note also that the collectors are different sizes; that is why insolation on the two collectors in winter is about the same. Comparisons of fuel displaced in two different cities are influenced by the size of the collector used in each, and the optimal size is in turn influenced by fuel prices and tax considerations.

Electric prices in New York are triple those in Seattle, and gas prices in Washington are double those in Tulsa and nearby cities. Other things equal, solar energy will be more viable in New York, where gas prices are high and electric prices very high, than they will be in Evansville, which has a fairly similar climate and almost identical tax benefits, but very low gas and electric prices. Gas prices are low throughout the Midwest, while electric prices are low near cheap hydropower and in coal country.

Tax benefits, which repay 57-94% of investment for someone in a 33% tax bracket, come in many forms. The federal tax credit of 40% of investment, assumed collected as a refund a year after the system is installed, repays 35.3% of the capital invested, on a present value basis. Federal tax deductions can be quite valuable for someone in the 33% marginal tax bracket. They repay from 25.8% of investment costs in states which have no income taxes to 21.7% in Minnesota, which has the highest marginal state tax rate for a $45,000 taxable income. State tax deductions repay 0 to 12.5% of investment cost, giving a combined range of 25.8% to 34.2% for state and federal tax deductions. These deduction benefits may be under 10%, however, for moderate income households. State tax credits, several of which change

TABLE 12. Present Value of Tax Savings on Solar Systems as Proportion of Investment Costs

(for taxable income of $45,000, 13% interest rate)

Highest		Lowest	
Massachusetts	94%	Connecticut	57%
Arizona	94	Tennessee	58
Kansas	91	Pennsylvania	59
Oklahoma	90	Washington	59
Colorado	89	Nevada	59
Oregon	87	South Dakota	59
Vermont	86	Illinois	60
Virginia	85	New Jersey	60
North Carolina	85	Mississippi	60
Nebraska	85	Wyoming	60
Minnesota	84	Texas	61
New Mexico	83	Florida	61
Indiana	82	Louisiana	61
New York	80	Kentucky	61
North Dakota	77	Maryland	61
California	76	Missouri	62
		West Virginia	62

from year to year, currently range from 0% to 35%, being worth 0% to 31.0% of investment cost. Dealers in three of nine states surveyed reported that no sales tax was charged on their systems, including two of the three states among the nine which have no income tax. Table 12 shows the total proportion of investment paid for through taxes in many states.

Energy and Cost Projections

The model projects energy savings. Conventional fuel use for water heating varies considerably, being 77% more in Duluth than in Honolulu. Variation in fuel displaced by a solar DHW system is influenced by the size of the optimum collector. Tables 13 and 14 show the large range of conventional fuel use, net fuel displaced, and fuel displacement fraction.

The model also projects cost savings. Two maps present net savings across the country. Tables 16 and 17 show the range of component costs and savings. Table 15 gives rough costs for conventional water heaters.

Tables 13 and 14 present fuel displacement data for 16 cities. Appendices C-1 and C-2 present the same data for all 69 cities. Conventional fuel use includes end use, storage losses, and heat which goes up a gas flue,but excludes gas pilot use. Cohen (5) notes the possibility of combining a pilotless ignition on a gas water heater with a flue damper, for use when there is no flame. That $125 investment can save 3.2-3.5 $\bar{M}$Btu a year. This study assumes 1) a pilot in a regular water heater and in the solar/gas backup, or 2) a pilot in neither - yielding the same fuel saving and capital cost in either case, that is, no net cost or saving. Net fuel displaced is gross fuel displaced - 85% of engineering model projections - less operating energy. Solar fraction is the net fraction of conventional fuel use displaced by the solar DHW system.

TABLE 13. Energy Data for Optimum Solar/Electric Systems, for Selected Cities

City		Type[a]	Size (sq m)	Conventional Fuel Use (kWh)	Net Fuel Displaced (kWh)	% Solar Fraction
Augusta	ME	S	4.5	4500	2504	56
Boston	MA	S	6.0	4049	2573	64
Casper	WY	S	3.8	4362	2960	68
Denver	CO	S	3.8	4112	2916	71
Detroit	MI	Gs	3.8	4125	2229	54
Duluth	MN	S	6.0	4734	2824	60
Honolulu	HI	T	3.8	2680	2134	80
Houston	TX	T	3.8	3093	2049	66
Little Rock	AR	D	3.0	3424	1972	58
Los Angeles	CA	T	3.8	3489	2515	72
Miami	FL	T	3.8	2739	2118	77
New York	NY	Gs	3.8	3886	2353	61
Pittsburgh	PA	Gs	3.8	4096	2147	52
Portland	OR	Gs	3.8	3977	2045	51
Reno	NV	S	3.8	4154	2945	71
Seattle	WA	D	6.0	4061	2139	53

a: D - draindown
Gs- glycol with selective surface
S - silicone
T - thermosyphon

TABLE 14. Energy Data for Optimum Solar/Gas Systems, for Selected Cities

City		Type[a]	Size (sq m)	Conventional[b] Fuel Use (M̄Btu)	Net Fuel Displaced (M̄Btu)	% Solar Fraction
Amarillo	TX	Gr	3.0	16.92	6.94	41
Augusta	ME	S	3.8	20.47	11.21	55
Boston	MA	Gs	4.5	18.42	11.48	62
Denver	CO	S	3.8	18.71	13.63	73
Detroit	MI	Gs	3.8	18.77	10.77	57
Duluth	MN	S	4.5	21.54	11.78	55
Hartford	CT	S	3.0	18.93	8.59	45
Honolulu	HI	T	3.8	12.19	10.15	83
Houston	TX	T	3.0	14.07	9.20	65
Los Angeles	CA	T	3.8	15.85	12.63	80
Miami	FL	T	3.0	12.46	9.44	76
New York	NY	Gs	3.8	17.68	11.22	63
Pittsburgh	PA	Gr	3.8	18.63	8.83	47
Reno	NV	S	3.0	18.90	12.73	67
San Diego	CA	T	3.8	15.57	12.50	80
Seattle	WA	D	3.0	18.47	7.36	40

a: D - draindown
Gr- glycol with regular surface
Gs- glycol with selective surface
S - silicone
T - thermosyphon

b: Not including about 3.3 M̄Btu pilot use.

In both Tables 13 and 14, note that a quarter of the cities have DHW systems displacing more energy than Miami DHW uses. Again, fuel displacement fractions can be far higher than one could expect with a single storage tank and a high hot water temperature. Duluth, using a collector 58% larger than one in New York, gathers 20% more energy. In Seattle the solar fraction increases 33% by increasing the collector size 100%. Denver, Reno, and Los Angeles displace the most gas (net). Pittsburgh, Seattle, and Portland are all very cloudy, and so have consistently low solar fractions. But the smallest net gas displacement is in Amarillo! Gas is very cheap there and Texas has no state tax benefits, so a small cheap system there minimizes net losses.

The two maps in Figures 7 and 8 show estimated areas where solar DHW systems are economically feasible, according to the NPV criterion and the projections from the base case. The first map shows solar/electric systems preferable to electric water heaters in 44 of the 69 cities. A glance at the map emphasizes the importance of tax benefits; compare Indiana, South Dakota, and Connecticut with their neighbors. In twelve cities the annualized net saving is projected to be over $100: Albuquerque, Boston, Denver, Honolulu, Los Angeles, Miami, New York, Oakland, San Diego, Tucson, Tulsa, and Wichita. The map is based on the use of customer marginal prices for all-electric homes. Use of company average residential electric prices results in viability in seven more cities net: Baltimore, Casper, Dallas, El Paso, Jackson, Little Rock, Madison, and Shreveport, but not Detroit.

The solar/gas map (Figure 8) is a great contrast, due to the much lower price of natural gas. Only in parts of Arizona is a non-thermosyphon system economical. Using average instead of marginal residential gas prices yields projected viability also near Roanoke, Norfolk, and Denver.

FIGURE 7. Solar/Electric DHW Economic Feasibility, 1984
(using tax credits; natural gas unavailable)

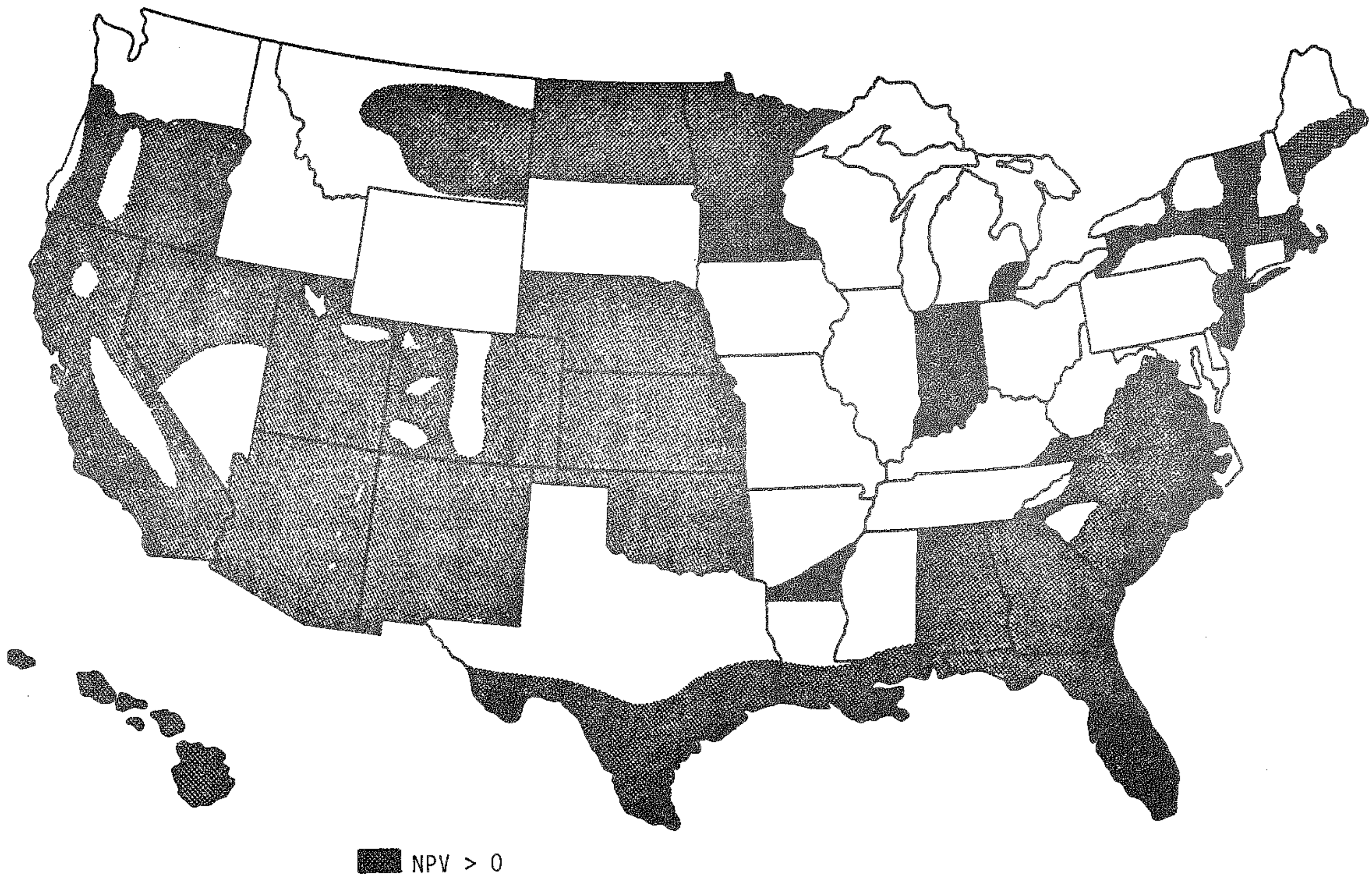


FIGURE 8. Solar/Gas DHW Economic Feasibility, 1984
(using tax credits)

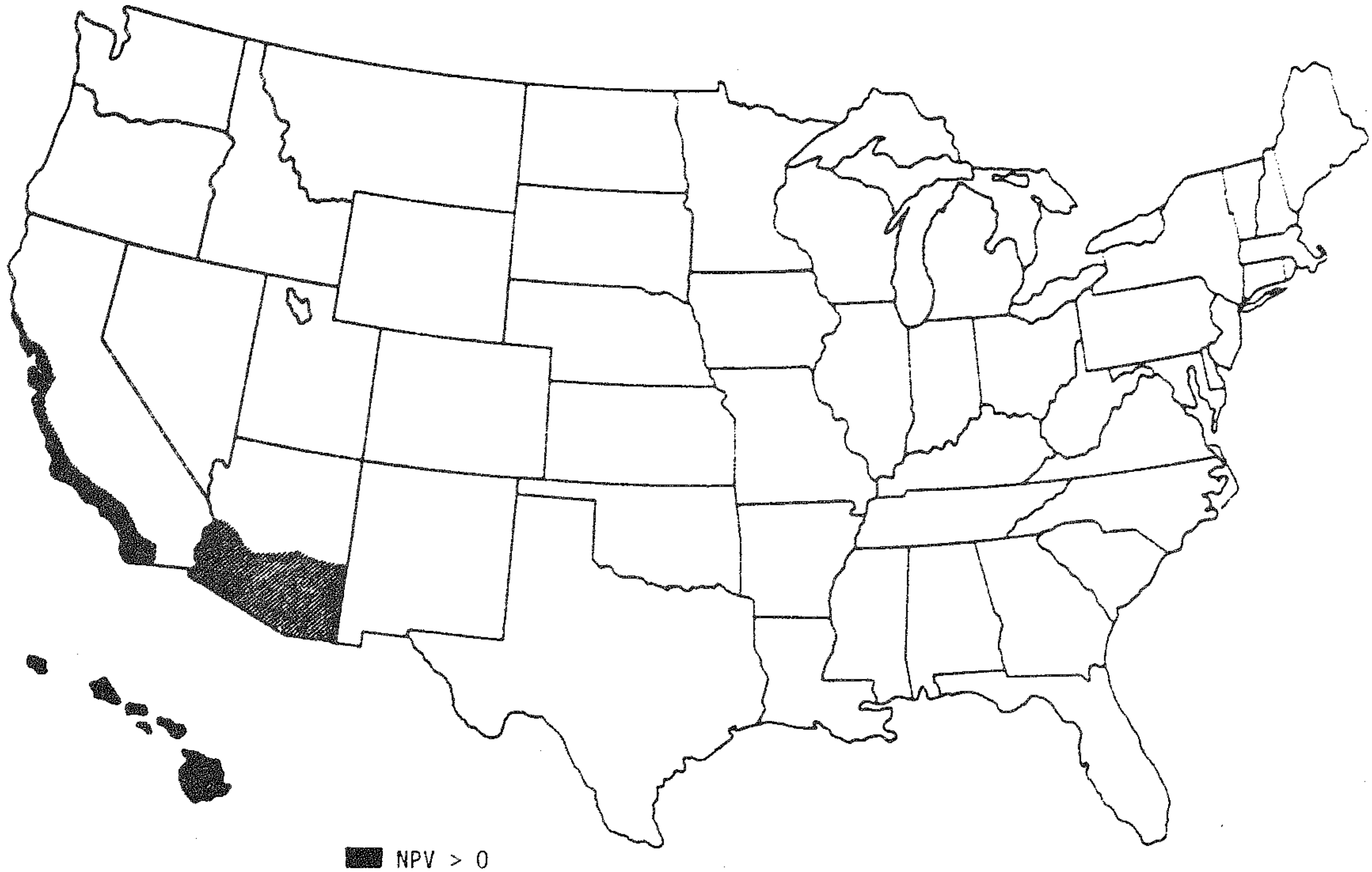


Table 15 below gives rough approximations of the annualized costs of owning and operating a conventional electric or gas water heater in a few selected cities. These can be used to put the numbers from Tables 16 and 17 into perspective, as in whether a solar system might be expected to cost 3% less or 30% less, 5% more or 50% more. Table 15 uses base case assumptions, including a 13% interest rate for 20 years. Hence the annualizing factor is .1423, about 1/7. So the discounted life cycle cost is about 7 times the numbers listed below. A further assumption is that non-pilot energy use increases annually, at the rate of $A * e^{.01t}$, where A is the initial conventional fuel use from Tables 13 and 14 and t is the year. In other words, gas heater efficiency declines smoothly over 20 years, from 75% to 60%, excluding pilot use. Electric efficiency is treated similarly.

The costs are almost entirely fuel costs; the others account for only about $20 annualized. A conventional water heater can be purchased for a little over $150, or about $20-25 annualized. Tax credits are not available, but interest deductions on income taxes can rebate $5-8 annualized this investment cost. Operation and maintenance costs are quite minimal, projected about $1 a year annualized. Gas pilot use is part of fuel cost.

TABLE 15. Approximate Annualized Costs for Conventional Water Heaters

City		Electric	Gas	City		Electric	Gas
Augusta	ME	$ 760	$ 570	Los Angeles	CA	$ 530	$ 320
Boston	MA	620	350	Miami	FL	470	240
Denver	CO	540	310	New York	NY	970	410
Detroit	MI	920	360	Pittsburgh	PA	550	340
Duluth	MN	590	410	Reno	NV	700	380
Honolulu	HI	590	400	Seattle	WA	330	310
Houston	TX	490	220				

TABLE 16. Annualized Costs and Savings for Optimum Solar/Electric Systems, Selected Cities

City		Operation Cost	Maintenance Cost	Capital Cost	Fuel Saving	Tax Saving	Net Saving
Augusta	ME	59	84	505	334	321	7
Boston	MA	82	91	598	321	565	114
Denver	CO	44	74	462	311	413	143
Detroit	MI	54	101	427	352	291	62
Duluth	MN	49	105	598	298	504	51
Honolulu	HI	10	50	327	321	239	173
Houston	TX	7	48	327	248	200	67
Las Vegas	NV	14	112	363	195	215	- 80
Los Angeles	CA	6	48	327	304	249	171
Miami	FL	7	48	327	276	200	129[a]
New York	NY	77	88	455	409	362	151
Pittsburgh	PA	42	104	455	236	268	- 97
Portland	OR	24	73	455	203	394	44
Reno	NV	63	77	462	379	269	44
San Diego	CA	12	49	327	340	249	202
Seattle	WA	12	87	470	183	275	-110

a: includes rebate by electric utility

TABLE 17. Annualized Costs and Savings for Optimum Solar/Gas Systems, Selected Cities

City		Operation Cost	Maintenance Cost	Capital Cost	Fuel Saving	Tax Saving	Net Saving
Augusta	ME	61	76	462	196	294	-110
Boston	MA	54	96	455	143	430	- 32
Chicago	IL	64	67	427	109	257	-192
Denver	CO	44	74	462	159	413	- 10
Detroit	MI	54	101	427	140	291	-150
Duluth	MN	48	88	505	155	426	- 60
Hartford	CT	65	67	427	122	244	-193
Honolulu	HI	10	50	327	182	239	+ 34
Houston	TX	7	45	306	96	187	- 74
Los Angeles	CA	6	48	327	162	248	+ 29
Miami	FL	7	45	306	113	187	- 58
New York	NY	77	83	427	165	339	- 82
Pittsburgh	PA	39	92	406	108	238	-190
Reno	NV	63	70	427	166	248	-146
San Antonio	TX	6	42	285	93	174	- 65
Seattle	WA	13	60	327	85	192	-103

Tables 16 and 17 show cost and savings breakdowns for 16 selected cities, covering the range from high to low in most categories. Appendices C-3 and C-4 present this data for all 69 cities. In only one city, for one fuel, electricity in San Diego, are projected fuel savings greater than capital costs. Only in Honolulu are gas fuel savings even half of capital costs. Tax savings outweigh electric fuel savings in two thirds of the cities and gas fuel savings everywhere. For eleven cities, projected fuel savings in a solar/gas system are less than projected operation and maintenance costs, including Boston, Chicago, Detroit, Hartford, and Pittsburgh. In several other cities, gas fuel savings are barely larger. But for solar/electric systems, projected fuel savings are always at least 54% greater, and at least 81% more except in Las Vegas and Pittsburgh. Note the highest gas savings are in Augusta and Honolulu, where natural gas is unavailable.

Variations on the Base Case and Future Years

Changes in several parameters from the base case assumptions affect substantially solar DHW economic feasibility. Among these are initial year of investment, presence or absence of tax credits, actual average fuel displaced, volume of hot water use, real interest rates, real fuel price inflation, and marginal tax brackets (via taxable income). Figures 9-12 show areas where solar DHW systems will have positive NPV's, using base case assumptions, but in future years and/or without tax credits. Substantial changes in any other of the parameters could lead to a change of about ± $30 in annualized net saving.

Figures 9-10 show feasible solar areas assuming present tax credits are extended for five years. Figures 11-12 show the few areas where a solar/electric investment is recommended if tax credits are subtracted.

FIGURE 9. Solar/Electric DHW Economic Feasibility, 1989 with Tax Credits
(credits at 1984 levels; natural gas unavailable)

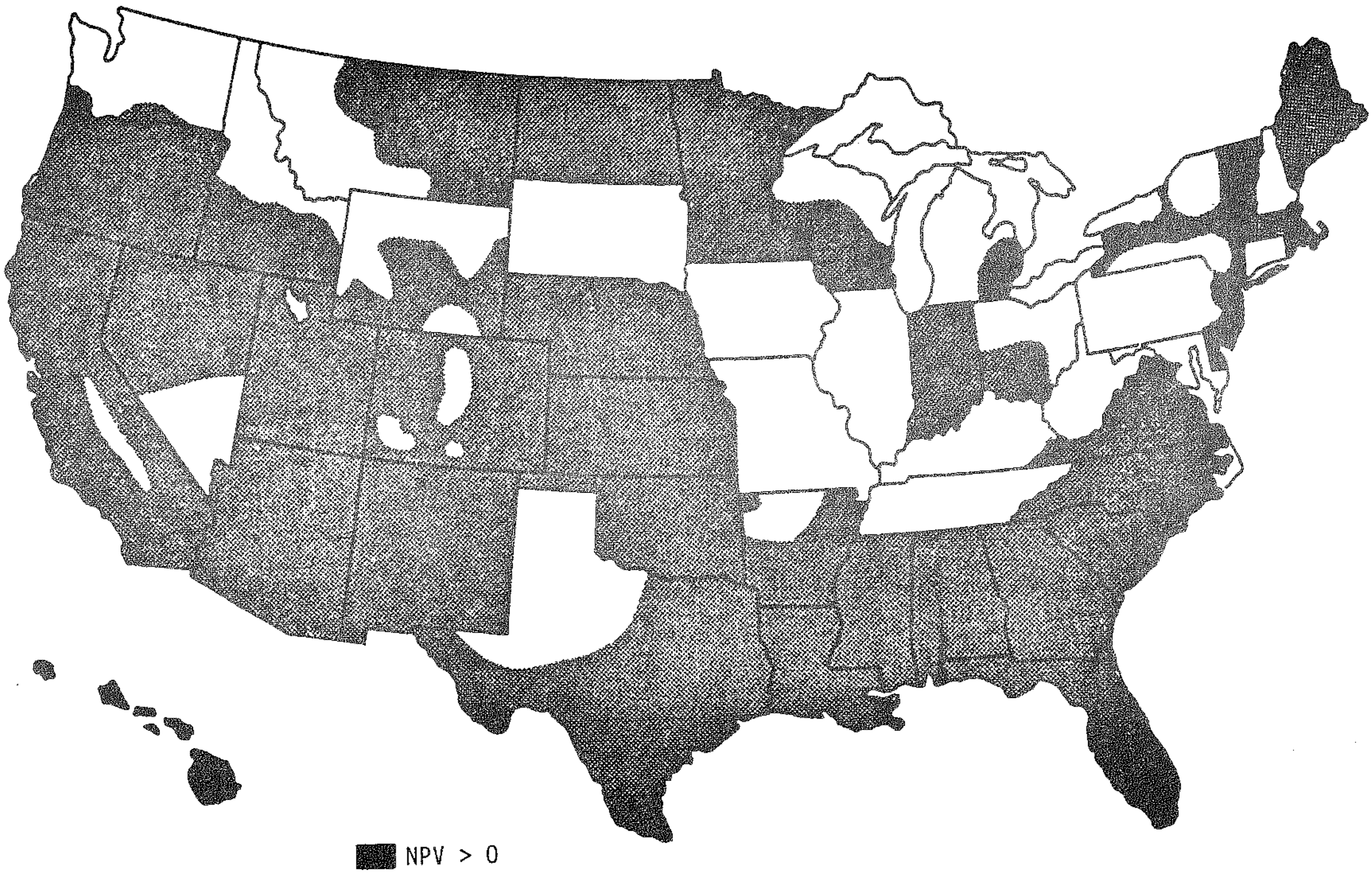
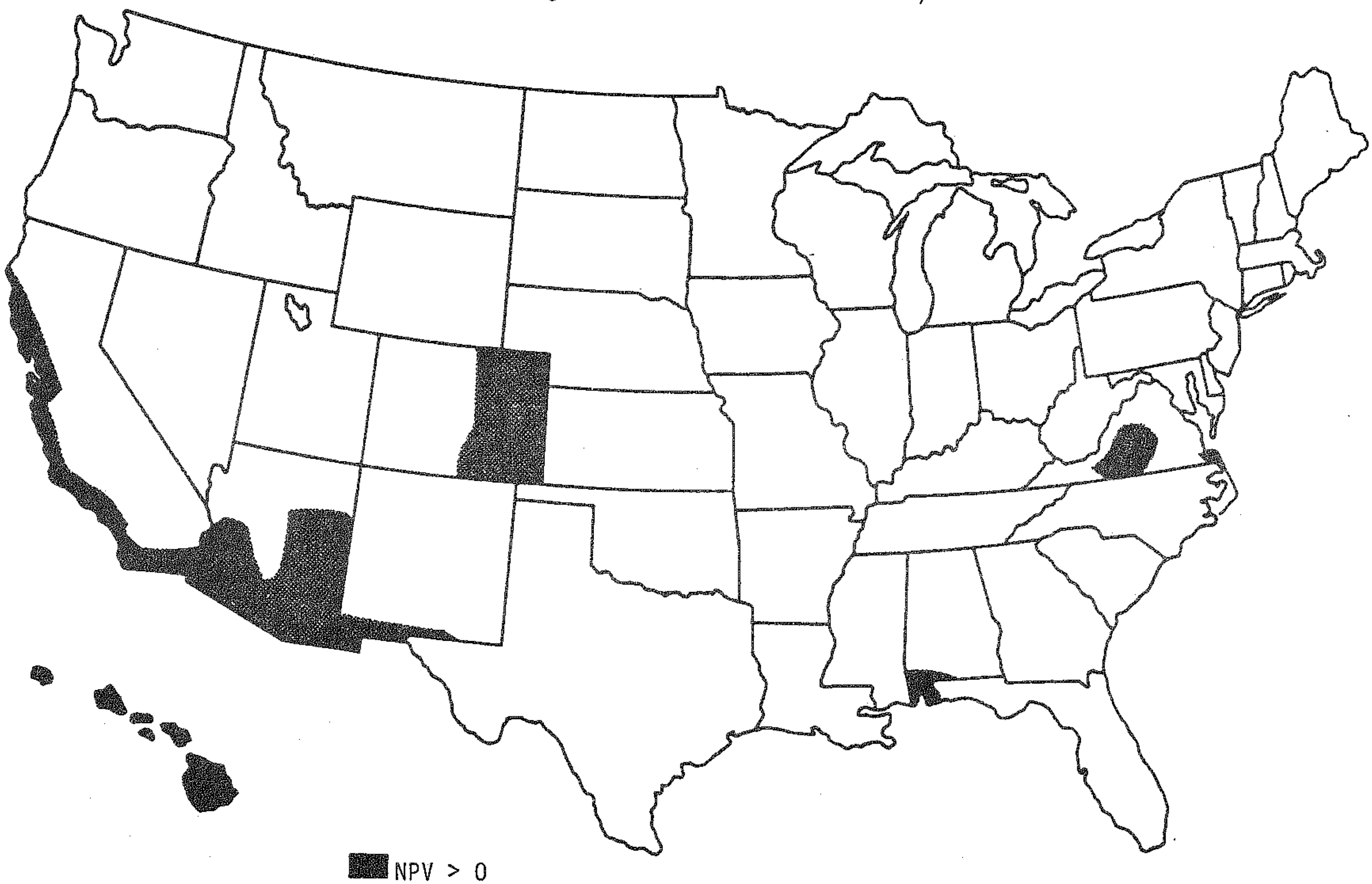


FIGURE 10. Solar/Gas DHW Economic Feasibility, 1989 with Tax Credits (using tax credits at 1984 levels)



If tax credits expire and high equipment costs do not fall, solar/gas DHW systems are economically viable nowhere in the U.S. this century.

Figure 9 is for solar/electric systems in 1989, when projected real electric prices are 12% higher. It is almost the same as a map for 1984 based on customer average prices. Solar/electric DHW systems would be viable where more than 75% of Americans live and 85% of new housing is built. Figure 10 is for solar/gas DHW systems in 1989, when projected real gas prices are 35% higher. It closely resembles a 1984 map based on average prices, except that Mobile is added. The maps in Figures 11 and 12 show a very limited area favorable to solar/electric DHW systems when no tax credits are allowed. All four maps assume no real price change in the installed cost of solar DHW systems of given size and quality, either over time or when tax credits are eliminated. See next chapter for discussion.

A favorable change in one of the other parameters, yielding a $30 greater annualized saving for solar DHW systems, increases by ten cities each (electric or gas) the number of places with positive NPV's. For an average city, among such changes are 80 gallons/day of hot water use, a 3% real interest rate (sunny areas only (6)), real gas prices rising 3½% per year after 1986 or real electric prices rising 2½% a year, or very few initial system "bugs" and corrosion which proceeds quite slowly. Then to Figure 7 for solar/electric systems, one would add areas around Boise, Casper, Columbus, Dallas, El Paso, Jackson, Little Rock, Madison, Memphis, and Shreveport. For solar/gas DHW systems, one would then add to Figure 8 the areas around Charlotte, Denver, Durango, Medford, Mobile, Norfolk, Portland, Raleigh, Roanoke, and Tulsa.

An unfavorable change of the same magnitude leaves ten fewer cities where solar/electric DHW systems are recommended, and only Honolulu where a

FIGURE 11. Solar/Electric DHW Economic Feasibility, 1984-1989 without Tax Credits
(natural gas unavailable)

FIGURE 12. Solar/Electric DHW Economic Feasibility, 1994-1999 without Tax Credits (natural gas unavailable)

solar thermosyphon/gas system is viable. Such changes include 45-50 gallons a day of hot water use, a taxable income of $20-25,000 (marginal tax rates two thirds as great), a 20% reduction in gas displaced or real gas prices rising only 1% a year after 1986, or a 10% reduction in electricity displaced or steady real electric prices over the next 20 years. Solar/electric systems (compare Figure 7) would then not be viable in Atlanta, Augusta, Bismarck, Columbia, Evansville, Fort Wayne, Helena, Newark, Syracuse, and Washington.

V. CONCLUSIONS

Summary

Solar domestic hot water heating is price competitive today with electric water heating in two thirds of the country, and with natural gas water heating in Hawaii, on the California coast, and in parts of Arizona and Colorado. The economic viability of solar DHW systems depends on three types of geographic factors: climate, variations in fuel prices, and differences in tax credits and tax rates. Higher fuel price escalation rates, higher incomes and marginal tax rates, higher volumes of hot water use, and lower real interest rates all create more favorable situations for solar investments. Solar capital costs are consistently greater than fuel savings and have not decreased over time.

Using an optimal storage arrangement, solar/electric DHW systems have positive annualized net savings in 44 of 69 cities in the study, using the base case economic assumptions, and in 51 of 69 if average customer prices are used. But solar water heating competes successfully with gas water heat in only 5 or 7 cities today, depending on whether marginal or average customer gas prices are used. If tax credits are abolished and there is no decline in the installed costs of solar DHW systems, the picture is very different. Solar systems then compete successfully with electric resistance water heating only in Hawaii and on the California coast, and with gas nowhere. In contrast, if tax credits are retained and pricing is adopted based on the cost of new gas supplies, solar DHW systems could compete successfully with gas in about 20 cities. (See below.)

Three geographies are important in regional variation of solar economics. Cold places need considerably more heat than warm ones, and so may collect more solar heat with an optimum system, even if a smaller fraction of the need. Other things equal, places with clear skies are much better for solar systems than ones with cloudy skies. Fuel prices show a more than two to one variation from place to place, with corresponding implications for fuel savings and solar economics. Most important is the geography of taxes. Tax savings repay 57-94% of capital costs and usually outweigh fuel savings. Tax credits are the most important, but the value of tax deductions is also considerable for people in high tax brackets. A measure of the relative importance of the three factors is that a solar/electric system is a far better investment in Duluth than in Las Vegas.

The base case assumes 61 gallons/day of hot water use, a $45,000 taxable income, 6% real interest rates, and gas and electric real price escalation rates averaging 3.0% and 1.5% per year. A large family using 100 gallons a day of hot water would find a larger system worthwhile, for perhaps 70% greater fuel savings with a 15% larger investment. A lower taxable income, perhaps with a marginal tax rate of 14%, might yield total tax savings 15-20% less, making a solar investment less attractive. Higher fuel price escalation rates certainly make solar investments more attractive, but far faster gas price increases would be needed to make a solar/gas investment attractive many places where freezing temperatures are expected. Current real interest rates near 8% are at historic highs, which discourages solar investments severely, as they do other investments. A fall in home rates to near 3% could make a significant difference in annualized savings in sunny places, where future fuel savings would be discounted much less.

Issues Outstanding

The existence of tax credits probably keep capital costs substantially higher than they would be otherwise. Tax credits decrease the price of solar energy, just as the practice of average cost pricing (instead of prices based on the marginal cost of new sources) lowers the price of fuels against which solar energy competes. Although solar energy is cheaper than electric energy for water heating in the larger part of the country, the circumstances where it would be installed in preference to gas water heat are more limited.

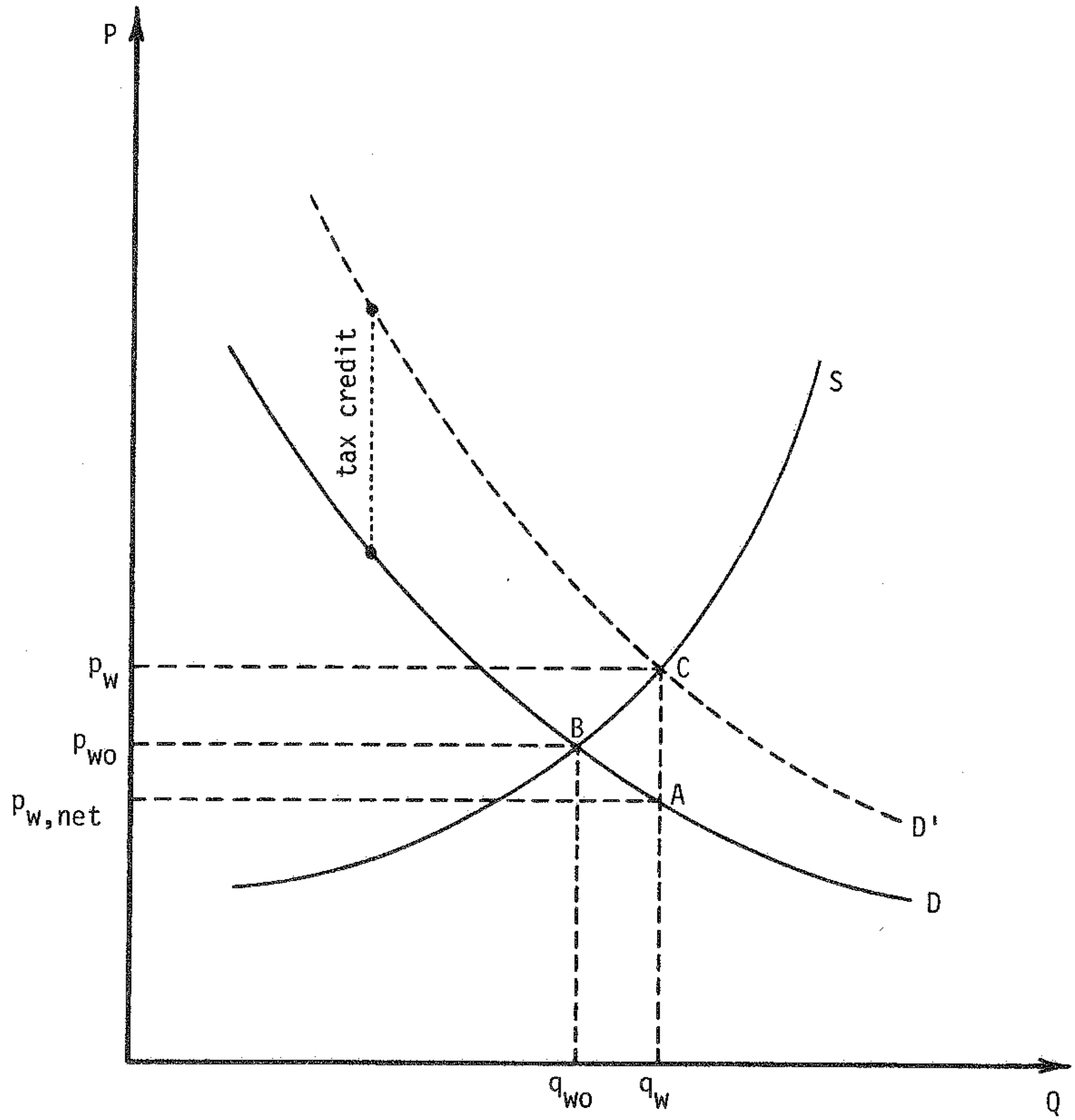
Two reasons come to mind why solar capital costs have not fallen over time. One is that quality (reliability,low repair costs, and larger energy gain) has increased markedly, and prices reflect this. The other is that tax credits may elevate the selling price of a solar system,as in Figure 13.

Figure 13 assumes that solar water heating systems have an upward sloping supply curve, characteristic of most goods. S shows how many water heating systems the industry will supply for a given price. D is the aggregate consumer demand curve, without tax credits. D' is the demand curve with a tax subsidy. With tax credits, an equilibrium occurs at C, where the subsidized demand curve intersects the supply curve S. q_w DHW systems are sold at price p_w. The consumer receives tax credit $p_w - p_{w,net}$. So the consumer pays only $p_{w,net}$ after the tax credits. Without tax credits, the equilibrium is at B. This yields a smaller quantity q_{wo} and a lower price p_{wo}. The net price to the consumer, however, is higher than the price $p_{w,net}$ which s/he can achieve with tax credits.

The maps in Figures 11-12 have neglected this effect.

Determining the sizes (by state) of the effect is a very complex undertaking and beyond the scope of this study. But simple assumptions

FIGURE 13. Possible Effect of Tax Credits on Price of Solar DHW System



S: supply curve for industry

D: demand curve for solar DHW systems

D': new demand curve, with tax credits

p_w: current price of solar DHW system

p_{wo}: price of solar DHW system in absence of tax credits

$p_{w,net}$: current price, less tax credits claimed by buyer will permit an indication of the size of the effect. Suppose the industry supply curve S for solar DHW systems is given by $p = nq$. Suppose demand elasticity is the same, so that D is $p = a - nq$. Demand D' induced by a 67% tax subsidy then is $p = 3(a - nq)$. In this case the elimination of tax credits would decrease the selling price of solar systems by one third (1). Indeed, the dealer price survey found the same 64 ft^2 system selling for $3550 in Reno but $4150 in Boston (2). The present value of tax credits repays 66.4% of a system's capital cost in Boston, but only 35.4% in Reno. Assuming the difference is due <u>only</u> to tax credits, an extrapolation suggests that a system might sell for $2865 without tax credits, a reduction of 31% from the Boston figure (3). So it seems quite possible that prices are now substantially higher than they would be without tax credits and that elasticities of supply and demand are comparable.

Bezdek (4) observed that solar energy competes with natural gas whose residential price is based on average wellhead price, using "rolled-in" prices, instead of on the cost of new supplies which solar energy effectively displaces. The average wellhead price of natural gas in September 1983 was about $2.66/mcf (5), but wellhead prices in January 1983 ranged from $.29/mcf to $9/mcf (6). If 1) the wellhead price of new supplies is $5/mcf, 2) marginal residential prices were based on wellhead prices of new supplies plus current distribution and overhead costs, and 3) consumer prices increased 2%/year from this base, then gas fuel savings would be about 16% greater per city in present value terms (7), making solar/gas systems cost competitive with gas in 9 cities. Similarly, if the price of new supplies at the wellhead is triple the average price and assumptions 2 and 3 hold, fuel savings would be 58% greater and solar/gas systems would be competitive in 32 cities. If there were no tax credits, solar/gas systems would be competitive only in Hawaii in the first case, and in four cities in the second case (8). This suggests that tax credits at current levels may offset the lack of marginal cost pricing in the gas market.

Solar/electric DHW systems are cheaper than electric DHW systems in the larger part of the country, but why should anyone buy a solar system when a gas water heater is available? Recalling the introduction, half the new homes in the country are equipped with expensive electric resistance water heating. Chapman and Cole (9) suggest a reason: "The system with the lowest initial cost - electric - has the highest annual customer cost." A builder/contractor who depends on a low initial sale price to sell a home has an incentive to lower the initial cost of heating and water heating, unless buyers look closely at life cycle costs. But if buyers examine life cycle costs, in almost all places they would choose gas over solar for water heating. Thus at present, for homes using average volumes of hot water, it appears solar water heating would be confined to rural and other areas far from natural gas lines -- except in Hawaii, the California coast, and perhaps a few other areas. To the extent this is not the case, reasons other than economic ones are important to the buyers.

Notes for Chapter I.

1. Stephen Albright; Solar Domestic Hot Water Project: Interim Report; (Public Service Company of New Mexico, Albuquerque, March 1981).

2. American Gas Association; Gas Facts 1982; (American Gas Association, Arlington, Virginia, 1983); pp. 137-141.

3. Roger H. Bezdek, Alan S. Hirshberg, and William H. Babcock; "Economic Feasibility of Solar Water and Space Heating"; Science (March 23, 1979); pp. 1214-1220.

4. B. M. Cohen, R. W. Persons, M. J. Harris, and R. Arora; Solar/Gas Water Heater Characterization and Development: Final Report; (Gas Research Institute, Chicago, November 1983).

5. Kathleen Cole; Comparative Space and Water Heating Costs in New York State; (Cornell Agricultural Economics Staff Paper 80-8, Ithaca, NY, February 1980); pp. 2 and 23.

6. Robert M. Hodges; Cost Effectiveness of Solar System Heat Transfer Fluids; (Dow Corning Corp., Midland,MI, 1980).

7. S. Hooks; Solar Domestic Hot Water; (Long Island Lighting Company, Mineola, NY, September 1983).

8. Monthly Energy Review, December 1983; (U.S. Department of Energy (DOE/EIA-0035(83/12)),Washington, 1984), p. 20.

9. William D. Schulze, Shaul Ben-David, J. Douglas Balcomb, Roberta Katson, Scott Noll, Fred Roach, and Mark Thayer; The Economics of Solar Home Heating: Paper Prepared for the Joint Economic Committee of the United States Congress; (U.S. Government Printing Office, Washington, January 1977).

10. TRW Corporation; An Economic Analysis of Solar Water and Space Heating; (ERDA-Division of Solar Energy, Washington, November 1976; available through National Technical Information Service (DSE/2322-1)).

11. Richard A. Tybout and George O. G. Löf; "Solar House Heating"; Natural Resources Journal (April 1970); pp. 268-326.

12. Seven years after 1976, the price model accurately projected eight of ten states with fastest gas price growth, in a belt from New Mexico and Colorado to Alabama and Kentucky. It also correctly projected two of the five states with slowest price growth, including Tennessee, in the middle of the "fast" belt. Average actual annual real price increases during 1976-1984 have been faster in most states than the average projected by the model for 1976-1990. The national average increase has also been faster: about 8.3%, versus a median 6.2% projected. 1983 prices used for this comparison are from the 69 city utility survey in this study.

Notes for Chapter II.

1. Albright, op. cit., pp. 3.1-3.4, 4.1-4.4, A.5.

2. Bezdek et al.; op. cit.; p. 1216.

3. Cohen et al., op. cit., pp. 136, 137, 189, 294, 297-299, 312-315, 354-357.

4. Denver Post: Jan. 1-15, 1970; Jan. 1-15, April 1-15, and July 1-15, 1974.

   Minneapolis Tribune: Feb. 16-28, April 1-13, July 1-15, 1974.

   St. Louis Post-Dispatch: April 1-13, July 1-14, Dec. 16-29, 1974.

5. J. A. Duffie and W. A. Beckman; Solar Energy Thermal Processes (John Wiley and Sons, New York, 1974); pp. 83, 133-137. See also pp. 104, 105, 112, and 117.

6. Joseph R. Frissora; "Solar Technology: Time for a Realistic Appraisal"; ASHRAE Journal (November 1981); pp. 29-30. Mr. Frissora is President of Sunmaster Corp., which makes concentrating, evacuated-tube solar collectors.

7. Sally Hooks, op. cit., p. 9.

8. Pamela McKeever of Public Service Company of New Mexico, in a telephone conversation, March 1984.

9. W. H. McCumber, Jr.; Comparison of Actual Collector Array Performance with Predicted Performance; paper presented at Solar Heating and Cooling Systems Operational Results Conference in Colorado Springs, November 1978; (USDOE:SOLAR/0015-78/32). Mr. McCumber was working for IBM in Huntsville, Alabama, under DOE contract.

10. Prof. Douglas Paine (meteorologist in Cornell University's Department of Agronomy), telephone conversation in January 1984.

11. Schulze et al., op. cit., pp. 37-38.

12. TRW/ERDA, op. cit., p. 6; calculated from 56,500 Btu/day, 60° supply, 140° end use.

13. Tybout and Löf, op. cit., pp. 290-293.

14. Directory of Certified Water Heater Efficiency Ratings (Gas Appliance Manufacturers' Association, Inc., Arlington, Virginia, January 1983).

Notes for Chapter III.

1. Cohen, op. cit., p. 315.

2. 55% in the first year is from Albright of PSNM, op. cit., p. 3-4. 70% thereafter is from a telephone conversation with Pamela McKeever of PSNM in March 1984.

3. Hodges, op. cit.

4. Hooks, op. cit., pp. 4-5.

5. Albright, op. cit., pp. 6-1 to 6-3.

6. P. S. Chopra; Reliability and Materials Performance of Solar Heating and Cooling Systems; (U.S. DOE/Argonne National Laboratory; NTIS (SOLAR/0906-79/70), Springfield, Virginia, June 1979); pp. 8-10.

7. February 1984 telephone conversations with Frank Luck of Sunland Solar and Bruce DuCharme of Capital Solar, both of Denver, Colorado.

8. \$8.26/$\overline{\text{M}}$Btu is based on telephone quotes in March 1984 from two Ithaca NY heating oil distributors - Andree and Townsend - of \$1.189/gal., with 5¢ cash discount,and \$1.185/gallon. An average is

   $(\frac{1.189 + 1.139}{2} + 1.185)/2 = \$1.1745/\text{gallon}.$ Ithaca is in DOE Region 2,

   where in December 1982 residential heating oil prices were 4.3¢/gallon higher than the national average. (Monthly Energy Review, December 1983; US DOE/EIA-0035(83/12); pp. 94-95). So \$1.315/gallon is the current estimated national heating oil price. At .137 $\overline{\text{M}}$Btu/gallon, this is \$8.26/$\overline{\text{M}}$Btu. $(8.26/6.37)^{1/3} = 1.090$.

9. Leon Tucker, Nelson Hay, and Michael German; "Historical and Projected Natural Gas Prices"; Energy Analysis 1982 (September 10, 1982); page 2 of reprint by American Gas Association of Arlington, Virginia.

Notes for Chapter IV.

1. Despite their cost advantage, thermosyphon systems may well not be chosen. Since storage must be above the collector, a roof mounted collector is probably ruled out. But the storage tank may need to be on the roof, which might be viewed as ugly.

   The modelling process assumes tanks at uniform temperatures. But in thermosyphon systems, tanks are much hotter at the top than at the bottom. The flow rate, a product of heat-induced convection, should vary as temperatures change over a day, in contrast to constant flow rates with a pump. So the model's projections of fuel displaced are to be trusted less than those for other types of solar DHW systems.

In all 11 cities where thermosyphons were considered, draindown systems are optimum if a homeowner chooses not to have a thermosyphon. With base case assumptions, a 3.8 m^2 collector is optimum in all 11 for solar/electric DHW systems. A 3.0 m^2 collector is optimum in 9 of the 11 for solar/gas systems. The annualized saving for all 11 cities then is positive for solar/electric systems but negative for the 11 solar/gas systems.

2. Thermosyphon systems are projected to have low annualized maintenance and repair costs (2.1-2.4% of initial cost), due to almost no moving parts, little danger of freezing, and equable climate so that high operating temperatures leading to speedy corrosion are uncommon.

   Silicone systems also have low annualized maintenance costs, 2.1-2.7% of initial cost. They have more moving parts and some tendency to leak, but they are quite insensitive to temperature stress.

   Draindown systems show more variation in costs, from 2.1 to 7.3% of initial cost, with highest costs found for large systems in the desert.

   Drainback systems operate at higher temperatures than draindown ones, due to a heat exchanger, so they have much higher heat stress. They show variation in maintenance costs from 3.4 to 15.7%. The large costs are in cold places like Duluth, where draindown systems were not even examined.

   Glycol system costs vary from 2.2% of investment in many cities to 9.1% in very cold places. In deserts, collector temperatures often reach boiling; then expected annualized maintenance costs exceed annual capital costs.

   See Appendix C-5 for the cold stress indices for the 69 cities and for the heat stress indices for the two optimum systems in each city.

3. Cohen _et al._, _op. cit._, p. 333.

4. _Ibid._, p. 23.

5. _Ibid._, pp. 320-323, 337-346.

6. A drop in the real discount rate not only increases the discounted fuel savings, but also increases the discounted costs of operation and maintenance. If the drop is caused by a lower nominal interest rate, interest charges will be less and so will the discounted tax savings. In cities like Seattle, Boston, and Chicago, a lower real discount rate can actually make solar economics look slightly worse.

Notes for Chapter V.

1. S: $p = nq$ D: $p = a - nq$ D': $p = 3(a - nq)$

   By setting supply equal to demand (S = D), p = p or $nq = a - nq$. This implies an equilibrium at point B, where $q_{wo} = a/2n$ and $p_{wo} = a/2$. Solving for a similar equilibrium, but using tax credits, we have S = D' at point C. Substituting, $nq = 3(a - nq)$. Solving, $q_w = 3a/4n$ and $p_w = 3a/4$. The ratio of selling price without tax credits and with them is $p_{wo}/p_w = \frac{a/2}{3a/4} = 2/3$. The reduction in price from eliminating tax credits is 1/3 of the price with credits, about 33%.

2. The prices given are the midpoints of narrow price ranges (e.g., \$3500-\$3600) for a 64 ft^2 Grumman system with a selective surface, glycol, and 80 gallons of storage. The quotes are from Bursaw Oil Corporation of Boston and from P&S Solar & Hardware of Reno.

3. Both places have a 40% federal tax credit. Boston has a 35% state credit but Reno has none. The present value of these in each state (after one year) is .664 and .354 of the sale price. The price should fall by x when credits are removed. $\frac{\$4150 - \$3550}{x} = \frac{.664 - .354}{.664}$

   Solving for x, x = \$1285. So the extrapolated price without tax credits is \$4150 - \$1285 = \$2865, a 31% reduction from the price in Boston, where there is a 66% tax credit subsidy.

4. Roger H. Bezdek, Alan S. Hirshberg, and William H. Babcock; "Economic Feasibility of Solar Hot Water and Space Heating"; Science (March 23, 1979); pp. 1219-1220.

5. Monthly Energy Review (December 1983); U.S. Department of Energy (DOE/EIA-0035(83/12)), Washington.

6. Public Affairs News (February 1983); Cities Service Company, Public Affairs Division, Tulsa.

7. A wellhead marginal price of \$5 is \$2.34 more than the \$2.66 average wellhead price. Adding \$2.34 to the \$5.82 customer average marginal price from our survey yields \$8.16, an increase of 40.2%. Under marginal cost pricing, with 2%/year real price growth and 6% real discount rate, fuel savings will be

   $$1.402 * \sum_{i=1}^{20} (1.02/1.06)^i = 1.402 * 13.685 = 19.159 \text{ times } \$5.82/\text{mcf}.$$

   Under the current average cost pricing regime, fuel savings are

   $$\sum_{i=1}^{3} \left(\frac{1.09}{1.06}\right)^i + \left(\frac{1.09}{1.06}\right)^3 * \sum_{i=1}^{17} \left(\frac{1.02}{1.06}\right)^i = 3.172 + 13.309 = 16.482 \times \$5.82.$$

The ratio of fuel savings is 19.159/16.482 = 1.1624, a 16% increase in average fuel savings using wellhead marginal cost of $5/mcf. 16% of the fuel saving for each city in Appendix C-4 is added to the net saving there to determine whether a solar/gas system is now competitive.

8. This assumes that capital costs in Appendix C-4 are 25% lower, that fuel savings there are 16% or 58% higher, and that tax savings there for each city are decreased by the combined state and federal tax credits on the original capital cost. The other three cities are San Diego, Los Angeles, and Oakland.

9. Duane Chapman, Kathleen Cole, and Michael Slott; Energy Production, and Residential Heating: Taxation, Subsidies, and Comparative Costs; Cornell University, Department of Agricultural Economics; Ithaca, NY; March 1980; p. 32.

APPENDIX A. Typical Engineering Model Output (Bakersfield CA - March)

System: Draindown 3.0 m²
Instantaneous Efficiency: $.73 - 7.1 \frac{T_i - T_a}{I_c}$ $\frac{\text{Watts}}{°K*m^2}$
Absorber Surface: $\varepsilon_p = .95$
Pump Power: 40 Watts

Solar Storage: 225 liters
Backup Storage: 115 liters
Set Temperature: 340°K = 116.3°F
Daily Hot Water Use: 230 liters

Hours	Hot Water Use (ℓ)	Collector Heat Loss (W*hr)	Temperatures (°K) Air	Temperatures (°K) Coll-ector	Temperatures (°K) Storage Solar	Temperatures (°K) Storage Backup	Collector Conductance W/(°K*m²)	Heat Transfers (W*hr) Coll-Fluid	Heat Transfers (W*hr) Backup-Load	Heat Transfers (W*hr) Solar-Backup	Heat Transfers (W*hr) Fuel-Backup	Heat Losses (W*hr) Pipes	Heat Losses (W*hr) Storage Solar	Heat Losses (W*hr) Storage Backup
0:00	0	2	285.1	285.2	315.5	321.0	5.28	0	0	0	0	0	21	14
0:30	0	2	284.6	284.7	315.4	320.9	5.27	0	0	0	0	0	21	14
1:00	0	2	284.2	284.3	315.3	320.8	5.25	0	0	0	0	0	21	14
1:30	0	2	283.8	283.9	315.2	320.7	5.24	0	0	0	0	0	21	14
2:00	0	2	283.4	283.5	315.1	320.6	5.23	0	0	0	0	0	21	14
2:30	0	2	283.0	283.1	315.0	320.5	5.22	0	0	0	0	0	21	14
3:00	0	2	282.6	282.7	315.0	320.4	5.20	0	0	0	0	0	21	14
3:30	0	2	282.2	282.3	314.9	320.3	5.19	0	0	0	0	0	21	14
4:00	0	2	281.8	281.9	314.8	320.2	5.18	0	0	0	0	0	21	14
4:30	0	2	281.4	281.5	314.7	320.1	5.17	0	0	0	0	0	21	14
5:00	0	2	281.0	281.1	314.6	320.0	5.16	0	0	0	0	0	21	14
5:30	0	2	280.6	280.7	314.6	320.0	5.14	0	0	0	13	0	21	14
6:00	0	2	280.2	280.3	314.5	320.0	5.13	0	0	0	14	0	21	14
6:30	4.6	2	281.1	281.2	313.9	320.0	5.14	0	166	137	43	0	21	14
7:00	34.5	244	282.4	314.9	310.2	320.0	5.18	47	1247	1001	259	0	20	14
7:30	23.0	289	283.7	311.4	308.4	320.0	7.28	140	831	568	277	19	17	14
8:00	18.4	251	284.9	310.3	307.8	320.0	7.15	298	665	416	262	16	16	14
8:30	9.2	231	286.1	310.6	308.6	320.0	7.09	432	333	202	144	15	15	14
9:00	4.6	227	287.3	312.1	310.1	320.0	7.10	541	166	105	75	15	16	14
9:30	0	233	288.4	314.3	312.4	320.0	7.15	627	0	0	14	16	17	14
10:00	0	250	289.4	317.1	314.9	320.0	7.23	690	0	0	14	18	19	14
10:30	0	271	290.3	319.9	317.5	320.0	7.33	733	0	0	14	19	21	14

Hours	Hot Water Use (ℓ)	Collector Heat Loss (W*hr)	Temperatures (°K) Air	Temperatures (°K) Coll-ector	Temperatures (°K) Storage Solar	Temperatures (°K) Storage Backup	Collector Conductance W/(°K*m²)	Heat Transfers (W*hr) Coll-Fluid	Heat Transfers (W*hr) Backup-Load	Heat Transfers (W*hr) Solar-Backup	Heat Transfers (W*hr) Fuel-Backup	Heat Losses (W*hr) Pipes	Heat Losses (W*hr) Storage Solar	Heat Losses (W*hr) Storage Backup
11:00	0	295	291.1	322.8	320.3	320.0	7.43	756	0	0	14	21	23	14
11:30	9.2	322	291.8	325.7	321.7	320.0	7.53	759	333	335	11	23	25	14
12:00	4.6	336	292.4	327.2	323.4	320.0	7.63	756	249	263	0	25	27	14
12:30	0	352	292.8	328.8	326.0	320.0	7.68	733	0	0	14	26	28	14
13:00	0	381	293.2	331.3	328.4	320.0	7.74	680	0	0	14	28	30	14
13:30	0	410	293.4	333.4	330.5	320.0	7.82	610	0	0	14	29	32	14
14:00	18.4	437	293.5	335.1	328.8	321.6	7.89	524	665	889	0	31	34	14
14:30	0	421	293.5	333.0	330.5	321.5	7.94	461	0	0	0	32	35	14
15:00	0	437	293.3	334.1	331.4	321.4	7.87	355	0	0	0	31	34	14
15:30	0	456	293.0	334.6	332.1	321.3	7.91	233	0	0	0	32	35	14
16:00	0	469	292.6	334.6	332.1	321.2	7.92	106	0	0	0	32	35	14
16:30	13.8	477	292.1	331.9	329.4	322.3	7.92	0	499	670	0	32	33	14
17:00	18.4	447	291.4	318.8	326.1	323.3	7.84	0	665	806	0	30	30	15
17:30	4.6	393	290.7	296.8	325.2	323.3	7.39	0	166	180	0	21	30	15
18:00	4.6	332	289.9	290.0	324.4	323.2	6.27	0	166	176	0	4	30	15
18:30	0	2	289.5	289.6	324.3	323.1	5.42	0	0	0	0	0	29	15
19:00	18.4	2	289.1	289.2	321.5	323.2	5.40	0	665	688	0	0	29	15
19:30	0	2	288.7	288.8	321.4	323.1	5.39	0	0	0	0	0	27	15
20:00	0	2	288.3	288.4	321.3	322.9	5.38	0	0	0	0	0	26	15
20:30	18.4	2	287.9	288.0	318.8	322.6	5.37	0	665	634	0	0	26	15
21:00	0	2	287.5	287.6	318.7	322.5	5.35	0	0	0	0	0	24	15
21:30	0	2	287.1	287.2	318.6	322.4	5.34	0	0	0	0	0	24	15
22:00	13.8	2	286.7	286.8	316.9	321.9	5.33	0	499	443	0	0	24	15
22:30	9.2	2	286.3	286.4	315.7	321.4	5.32	0	333	282	0	0	23	14
23:00	0	2	285.9	286.0	315.6	321.3	5.30	0	0	0	0	0	22	14
23:30	0	2	285.5	285.6	315.5	321.2	5.29	0	0	0	0	0	22	14
	230.	8011					7.51	9481	8312	7794	1192	516	1173	674

APPENDIX B-1. Fuel Price Data[a]

City		Average Gas Use ($\bar{M}$Btu)	Gas Prices ($/$\bar{M}$Btu) Average	Gas Prices ($/$\bar{M}$Btu) Marginal	Average Electric Use (kWh)	Electricity Prices ($/$\bar{M}$Btu) Average	Electricity Prices ($/$\bar{M}$Btu) Marginal	All-Electric[b]
Albuquerque	NM	93	5.46	4.69	475	21.89	20.81	20.81
Amarillo	TX	120	4.12	3.86	600	22.52	20.73	13.92
Atlanta	GA	86	5.90	5.22	856	18.02	18.01	18.01
Augusta	ME	50c	13.02	11.25	565	23.57	21.66	21.66
Bakersfield	CA	79	5.61	6.80	490	21.65	25.67	21.56
Baltimore	MD	94	7.47	6.86	565	22.16	18.05	18.05
Birmingham	AL	110	6.03	5.02	885	19.89	15.59	15.59
Bismarck	ND	136	6.29	5.85	664	19.86	18.31	17.64
Boise	ID	71	7.35	6.71	1242	11.67	11.67	11.67
Boston	MA	92	7.38	6.68	432	33.09	32.58	22.58
Burlington	VT	107	6.39	5.79	749	16.56	18.97	18.97
Casper	WY	129	6.55	6.55	489	14.23	11.84	11.84
Charleston	WV	120	6.37	6.11	840	15.67	13.46	13.11
Charlotte	NC	93	6.48	5.95	1000	19.04	18.26	15.17
Chicago	IL	151	4.37	4.16	524	25.49	24.40	20.22
Columbia	SC	70	6.61	6.10	912	20.18	17.31	17.31
Columbus	OH	118	6.77	6.33	810	22.75	21.30	17.84
Dallas	TX	75	6.89	6.09	1054	18.97	17.32	15.22
Denver	CO	110	5.22	4.91	471	18.50	16.41	16.41
Des Moines	IA	125	5.70	5.22	666	26.76	25.00	14.04
Detroit	MI	150	6.59	5.99	520	19.27	29.16	29.16
Duluth	MN	140	5.86	5.73	617	15.51	17.11	14.66
Durango	CO	103	4.60	3.98	600	22.51	18.41	18.41
El Paso	TX	70	4.62	4.43	487	21.50	17.29	17.29
Evansville	IN	128	4.57	4.25	840	17.27	14.93	12.88
Ft Wayne	IN	140	5.10	4.39	560	18.46	13.15	13.15
Fresno	CA	58	5.15	5.37	760	21.06	25.60	19.75
Hartford	CT	88	8.24	6.66	623	29.27	25.81	23.17
Helena	MT	116	4.79	5.08	707	18.51	16.67	16.67
Honolulu	HI	23c	17.62	14.46	584	35.82	32.81	32.81
Houston	TX	65	5.99	4.92	980	23.21	21.79	21.79
Jackson	MS	81	6.21	4.94	923	20.54	15.67	15.67
Jacksonville	FL	34	6.95	5.71	897	21.31	19.84	19.84
Knoxville	TN	95	5.92	5.65	1000	13.74	12.86	13.34
Las Vegas	NV	98	5.18	4.50	1211	13.76	12.91	12.86
Lexington	KY	120	6.11	5.81	660	16.65	14.39	13.37
Little Rock	AR	96	4.24	3.79	764	21.70	19.11	14.33
Los Angeles	CA	79	5.61	6.80	387	19.73	19.73	19.73
Madison	WI	120	6.71	6.49	496	20.29	18.37	14.11
Medford	OR	78	7.18	6.72	1200	12.24	14.47	14.47
Memphis	TN	94	4.74	4.57	1000	13.97	13.00	13.65
Miami	FL	34	6.95	5.71	888	21.45	22.22	22.22
Mobile	AL	53	7.46	6.32	885	19.89	15.59	15.59

City		Average Gas Use ($\bar{M}$Btu)	Gas Prices ($/$\bar{M}$Btu) Average	Marginal	Average Electric Use (kWh)	Electricity Prices ($/$\bar{M}$Btu) Average	Marginal	All-Electric
New Orleans	LA	72	7.54	7.13	1149	17.34	17.00	15.90
New York	NY	75	8.26	7.12	275	44.66	39.90	32.33
Newark	NJ	90	7.11	6.31	438	29.16	25.15	26.72
Norfolk	VA	95	7.06	6.33	912	20.60	17.28	13.15
Oakland	CA	80	5.35	5.37	760	21.06	25.60	19.75
Omaha	NE	130	5.11	4.87	798	16.55	14.17	14.17
Orlando	FL	34	6.95	5.71	970	20.48	19.47	19.47
Philadelphia	PA	100	6.72	6.30	500	27.73	26.69	22.13
Pittsburgh	PA	149	5.84	5.53	475	26.39	23.34	16.34
Portland	OR	71	6.81	6.39	1061	13.94	14.08	14.08
Raleigh	NC	92	6.50	5.91	952	20.88	18.14	18.14
Rapid City	SD	123	6.82	6.43	576	20.70	17.56	12.74
Reno	NV	67	7.13	6.55	679	25.19	23.90	23.90
Roanoke	VA	107	7.01	6.55	889	18.31	16.57	16.57
St Louis	MO	124	6.13	5.58	750	16.91	15.67	15.67
Salt Lake City		115	4.81	4.15	542	23.53	23.53	21.17
San Antonio	TX	74	5.34	4.89	799	20.78	20.32	20.32
San Diego	CA	60	6.60	6.91	425	36.92	40.97	27.69
Seattle	WA	91	6.37	5.37	1407	9.83	11.40	11.40
Shreveport	LA	90	4.85	4.64	980	17.54	16.65	15.39
Springfield	MO	98	4.92	4.68	650	16.30	16.55	14.29
Syracuse	NY	96	6.02	5.24	500	18.06	15.20	15.20
Tucson	AZ	58	6.39	5.15	653	20.71	16.41	16.41
Tulsa	OK	103	4.47	3.90	852	17.03	13.88	14.69
Washington	DC	99	8.70	8.00	733	19.36	22.99	25.80
Wichita	KS	135	4.56	4.16	786	20.74	19.17	17.98
simple average			6.37	5.82		20.74	19.56	17.90

NOTES:

a - Sources: 1) Utility rate schedules, including monthly fuel adjustments, from correspondence with and telephone calls to the utilities in the cities named, between mid-November 1983 and mid-February 1984. See the Bibliography for a list of the utilities.

2) Average use figures were estimated in about half the cases, where utilities did not supply the information. Estimates are based on

i) Statistics of Privately Owned Electric Utilities in the United States 1981 (USDOE/EIA)

ii) Statistics of Publicly Owned Electric Utilities in the United States 1981 (USDOE/EIA).

b - The "all-electric" price is the customer's marginal price at a use level twice the company average, for all-electric homes.

c - Natural gas is unavailable in the area. Price is for LP gas or for synthetic gas.

APPENDIX B-2. State Tax Data Used

City		Tax Credits[a] %	Expires	Tax Rate on Sales DHW-b	Gas-c	Elect.	Marginal Income Tax[d] $45000	$24000	$16000
Albuquerque	NM	25	12/85	3.5%	4.5%	4.5%	5.3%	5.3%	5.3%
Amarillo	TX	--	-----	0	8.5	0	0	0	0
Atlanta	GA	0	-----	2.0	3.0	3.0	6.0	6.0	6.0
Augusta	ME	0	12/83	3.3	0	5.0	10.0	9.2	9.2
Bakersfield	CA	15	e	4.7	0	.5	11.0	11.0	8.0
Baltimore	MD	0	-----	3.3	0	0	5.0	5.0	5.0
Birmingham	AL	15f	12/85	2.7	2.2	2.2	5.0	5.0	5.0
Bismarck	ND	15	none	2.0	4.0	4.0	7.5	5.0	5.0
Boise	ID	7g	none	1.0	3.0	1.0	7.5	7.5	7.5
Boston	MA	35	12/85	5.0	0	0	13.0	12.8	12.5
Burlington	VT	25	e	2.0	0	0	7.9	5.3	3.8
Casper	WY	--	-----	2.0	3.0	3.0	0	0	0
Charleston	WV	0	-----	3.3	7.57	7.57	7.5	6.1	4.9
Charlotte	NC	25	none	3.0	0	0	7.0	7.0	7.0
Chicago	IL	0	-----	2.7	5.0	5.0	2.5	2.5	2.5
Columbia	SC	0	-----	2.7	1.0	1.0	7.0	7.0	7.0
Columbus	OH	10	12/85	3.3	0	4.75	3.5	3.0	2.5
Dallas	TX	0	-----	0	2.0	2.0	0	0	0
Denver	CO	30	12/85	3.0	3.5	3.5	8.0	8.0	8.0
Des Moines	IA	0	-----	2.0	6.0	6.0	11.5	9.0	8.0
Detroit	MI	8	e	2.7	9.0	9.0	4.6	4.6	4.6
Duluth	MN	20	12/85	3.3	8.0	8.0	16.0	14.0	12.8
Durango	CO	30	12/85	3.0	10.5	9.0	8.0	8.0	8.0
El Paso	TX	--	-----	0	5.0	5.0	0	0	0
Evansville	IN	25	12/84	2.7	5.0	5.0	1.9	1.9	1.9
Ft Wayne	IN	25	12/84	2.7	5.0	5.0	1.9	1.9	1.9
Fresno	CA	15	e	4.7	5.0	5.0	11.0	11.0	8.0
Hartford	CT	0	-----	5.0	5.0	0	1.0	1.0	1.0
Helena	MT	0	-----	0	4.0	4.0	11.0	10.0	9.0
Honolulu	HI	10	12/85	2.7	0	6.0	10.5	9.5	8.5
Houston	TX	--	-----	0	2.0	4.0	0	0	0
Jackson	MS	0	-----	3.3	0	0	4.0	4.0	4.0
Jacksonville	FL	--	-----	0	10.0	10.0	0	0	0
Knoxville	TN	0	-----	3.0	1.5	1.5	6.0	6.0	6.0
Las Vegas	NV	--	-----	2.3	5.0	5.0	0	0	0
Lexington	KY	0	-----	3.3	5.0	4.4	6.0	6.0	6.0
Little Rock	AR	6g	12/84	2.0	9.2	9.2	6.0	6.0	6.0
Los Angeles	CA	15	e	4.7	10.0	10.0	11.0	11.0	8.0
Madison	WI	8h	1/87	3.3	5.0	5.0	9.5	9.1	8.7
Medford	OR	25	12/85	0	2.0	2.0	6.0	6.0	6.0
Memphis	TN	0	-----	3.0	3.0	4.5	6.0	6.0	6.0
Miami	FL	--	-----	0	10.0	15.0	0	0	0
Mobile	AL	15f	12/85	2.7	2.2	2.2	5.0	5.0	5.0
New Orleans	LA	0	-----	2.0	3.0	3.0	4.0	4.0	4.0

City		Tax Credits %	Expires	Tax Rate on Sales DHW	Gas	Elect.	Marginal Income Tax $45000	$24000	$16000
New York	NY	15	12/86	4.0	14.35	14.35	14.0	14.0	10.0
Newark	NJ	0	-----	3.3	5.0	5.0	2.5	2.5	2.0
Norfolk	VA	25f	12/87	2.0	2.7	7.0	5.75	5.75	5.75
Oakland	CA	15	e	4.7	10.0	10.0	11.0	11.0	8.0
Omaha	NE	25f	12/86	2.0	0	5.5	5.6	3.7	2.7
Orlando	FL	--	-----	0	10.0	4.9	0	0	0
Philadelphia	PA	0	-----	4.0	0	5.5	2.2	2.2	2.2
Pittsburgh	PA	0	-----	4.0	4.9	5.0	2.2	2.2	2.2
Portland	OR	25	12/85	0	0	3.73	6.0	6.0	6.0
Raleigh	NC	25	none	2.0	6.0	0	7.0	7.0	7.0
Rapid City	SD	--	-----	2.7	0	5.5	0	0	0
Reno	NV	--	-----	3.5	2.0	2.0	0	0	0
Roanoke	VA	25f	12/87	2.0	10.0	10.0	5.75	5.75	5.75
St Louis	MO	0	-----	3.13	4.0	4.0	6.0	6.0	6.0
Salt Lake City		10	6/85	2.7	4.9	8.75	7.75	7.75	7.75
San Antonio	TX	--	-----	0	2.0	2.0	0	0	0
San Diego	CA	15	e	4.7	1.0	1.9	11.0	11.0	8.0
Seattle	WA	--	-----	3.0	2.0	2.0	0	0	0
Shreveport	LA	0	-----	2.0	2.0	0	4.0	4.0	4.0
Springfield	MO	0	-----	3.13	1.0	1.0	6.0	6.0	6.0
Syracuse	NY	15	12/86	4.0	4.75	4.75	14.0	14.0	10.0
Tucson	AZ	35f	12/87	2.7	9.2	9.2	8.0	8.0	8.0
Tulsa	OK	35f	12/90	1.3	3.0	3.0	6.0	6.0	6.0
Washington	DC	0	-----	4.0	5.0	5.0	11.0	10.0	9.0
Wichita	KS	30	1/86	2.0	5.0	5.0	9.0	8.5	7.5

NOTES:

a - Source is Solar Age magazine, May 1983. States with credits scheduled to expire in 1983 were called for updates.

b - Solar dealers in nine states reported sales tax rates on their equipment; six of those reported some tax. The State Tax Guide 1982 by the Commerce Clearing House was consulted for applicable rates in other states. In many cases the rate was not clear; in those, 6/9 of the regular sales tax rate was used.

c - In most places, the source is a written or telephone response from one or two utilities in a city. When neither utility supplied a tax rate, rates were used from the State Tax Guide 1982, or from another utility in the same state.

d - These are marginal tax rates on taxable incomes of $45000 and so on, from the World Almanac 1983.

e - Credits were renewed in 1983. No expiration date was ascertained.

f - Tax credit rate is scheduled to change from year to year.

g - State gives 100% deduction. The number is estimated equivalent credit.

h - Rate applies to new houses; a different one applies to retrofits. The rate also changes from year to year.

APPENDIX B-3. Characteristics of System Types

Type/Fluid	Selective Surface	Heat Exchanger	Specific Heat of Fluid (J/°K*kg)	Pump Power (Watts)	Fluid Flow Rate (kg/sec*m)	Susceptibility-to -Damage-Indices-- Cold	Heat
thermosyphon/H_2O	no	no	4186	none	.004	4	4
draindown /H_2O	no	no	4186	40	.014	4	4
drainback /H_2O	no	yes (.35)	4186	40	.014	3	1
glycol - H_2O	no	yes (.35)	3300	60	.018	1	2
glycol - H_2O	yes	yes (.35)	3300	60	.018	1	2
silicone	yes	yes (.35)	1700	90	.035	.1	.1
hydrocarbon oil	- - - - - - - - - - - - - not modelled - - - - - - - - - - - -					.2	.3

APPENDIX C-1. Energy Data for Optimum Solar/Electric Systems

City		Type[a]	Size (sq m)	Conventional Fuel Use (kWh)	Net Fuel Displaced (kWh)	% Solar Fraction
Albuquerque	NM	S	3.8	3752	2767	74
Amarillo	TX	S	3.8	3720	2703	73
Atlanta	GA	W	3.8	3533	2182	62
Augusta	ME	S	4.5	4500	2504	56
Bakersfield	CA	W	3.0	3211	2137	67
Baltimore	MD	Gs	3.8	3849	2388	62
Birmingham	AL	W	3.8	3445	2188	64
Bismarck	ND	S	4.5	4582	2802	61
Boise	ID	S	3.8	4071	2570	63
Boston	MA	S	6.0	4049	2573	64
Burlington	VT	S	6.0	4423	2553	58
Casper	WY	S	3.8	4362	2960	68
Charleston	WV	Gs	3.8	4013	2267	56
Charlotte	NC	W	3.8	3551	2257	64
Chicago	IL	S	3.8	4084	2305	56
Columbia	SC	W	3.8	3387	2247	66
Columbus	OH	Gs	3.8	4036	2220	55
Dallas	TX	W	3.8	3241	2213	68
Denver	CO	S	3.8	4112	2916	71
Des Moines	IA	S	4.5	4170	2669	64
Detroit	MI	Gs	3.8	4125	2229	54
Duluth	MN	S	6.0	4734	2824	60
Durango	CO	S	3.8	3862	2741	71
El Paso	TX	W	3.0	3295	2397	73
Evansville	IN	S	3.8	3795	2231	59
Ft Wayne	IN	S	4.5	4124	2344	57
Fresno	CA	W	3.0	3355	2149	64
Hartford	CT	S	4.5	4161	2352	57
Helena	MT	S	3.8	4489	2564	57
Honolulu	HI	T	3.8	2680	2134	80
Houston	TX	T	3.8	3093	2049	66
Jackson	MS	W	3.8	3307	2045	62
Jacksonville	FL	T	3.8	3117	2195	70
Knoxville	TN	W	3.8	3594	2109	59
Las Vegas	NV	W	3.8	3260	2462	76
Lexington	KY	Gs	3.8	3835	2297	60
Little Rock	AR	W	3.0	3424	1972	58
Los Angeles	CA	T	3.8	3485	2515	72
Madison	WI	S	4.5	4392	2599	59
Medford	OR	S	4.5	3958	2363	60
Memphis	TN	W	3.8	3488	2168	62
Miami	FL	T	3.8	2739	2118	77
Mobile	AL	T	3.8	3177	2118	67

City		Type[a]	Size (sq m)	Conventional Fuel Use (kWh)	Net Fuel Displaced (kWh)	% Solar Fraction
New Orleans	LA	T	3.8	3126	2123	68
New York	NY	Gs	3.8	3886	2353	61
Newark	NJ	Gs	3.8	3908	2346	60
Norfolk	VA	W	3.8	3613	2223	62
Oakland	CA	T	3.8	3721	2397	64
Omaha	NE	S	4.5	4151	2684	65
Orlando	FL	T	3.8	2939	2172	74
Philadelphia	PA	Gs	3.8	3870	2340	60
Pittsburgh	PA	Gs	3.8	4096	2147	52
Portland	OR	Gs	3.8	3977	2045	51
Raleigh	NC	Gs	3.8	3625	2423	67
Rapid City	SD	S	3.8	4301	2649	62
Reno	NV	S	3.8	4154	2945	71
Roanoke	VA	Gs	3.8	3797	2454	65
St Louis	MO	S	3.0	3698	2055	56
Salt Lake City	UT	S	3.8	4062	2701	66
San Antonio	TX	T	3.8	3098	2198	71
San Diego	CA	T	3.8	3423	2514	73
Seattle	WA	W	6.0	4061	2139	53
Shreveport	LA	W	3.8	3255	2156	66
Springfield	MO	S	3.0	3687	2094	57
Syracuse	NY	S	4.5	4220	2182	52
Tucson	AZ	S	3.8	3152	2322	74
Tulsa	OK	Gs	3.0	3468	2179	63
Washington	DC	Gs	3.8	3916	2372	61
Wichita	KS	S	4.5	3759	2656	71

NOTE:

a - D - drainback
Gr- glycol, regular surface
Gs- glycol, selective surface
S - silicone
T - thermosyphon
W - draindown

APPENDIX C-2. Energy Data for Optimum Solar/Gas Systems

City		Type[a]	Size (sq m)	Conventional[b] Fuel Use (MBtu)	Net Fuel Displaced (MBtu)	% Solar[b] Fraction
Albuquerque	NM	S	3.0	17.07	12.15	71
Amarillo	TX	Gr	3.0	16.92	6.94	41
Atlanta	GA	W	3.0	16.07	9.18	57
Augusta	ME	S	3.8	20.47	11.21	55
Bakersfield	CA	W	3.0	14.61	10.10	69
Baltimore	MD	Gr	4.5	17.51	10.64	61
Birmingham	AL	W	3.8	15.67	10.55	67
Bismarck	ND	S	3.8	20.85	12.32	59
Boise	ID	S	3.8	18.52	12.03	65
Boston	MA	Gs	4.5	18.42	11.48	62
Burlington	VT	S	4.5	20.12	10.76	53
Casper	WY	S	3.0	19.84	12.55	63
Charleston	WV	Gs	3.8	18.26	10.60	58
Charlotte	NC	W	3.8	16.15	10.91	68
Chicago	IL	S	3.0	18.58	9.55	51
Columbia	SC	W	3.0	15.41	9.48	62
Columbus	OH	S	3.0	18.36	8.68	47
Dallas	TX	W	3.0	14.74	9.42	64
Denver	CO	S	3.8	18.71	13.63	73
Des Moines	IA	S	3.0	18.97	10.55	56
Detroit	MI	Gs	3.8	18.77	10.77	57
Duluth	MN	S	4.5	21.54	11.78	55
Durango	CO	S	3.8	17.57	12.80	73
El Paso	TX	W	3.0	14.99	11.25	75
Evansville	IN	Gr	4.5	17.26	10.39	60
Ft Wayne	IN	S	3.8	18.76	10.32	55
Fresno	CA	W	3.0	15.26	10.18	67
Hartford	CT	S	3.0	18.93	8.59	45
Helena	MT	S	3.0	20.42	10.52	52
Honolulu	HI	T	3.8	12.19	10.15	83
Houston	TX	T	3.0	14.07	9.20	65
Jackson	MS	W	3.0	15.04	9.32	62
Jacksonville	FL	T	3.8	14.18	10.91	77
Knoxville	TN	W	3.0	16.35	8.87	54
Las Vegas	NV	W	3.0	14.83	10.73	72
Lexington	KY	Gr	4.5	17.45	10.27	59
Little Rock	AR	W	3.0	15.58	9.65	62
Los Angeles	CA	T	3.8	15.85	12.63	80
Madison	WI	S	3.8	19.98	11.90	60
Medford	OR	Gr	4.5	18.01	10.49	58
Memphis	TN	W	3.0	15.87	9.27	58
Miami	FL	T	3.0	12.46	9.44	76
Mobile	AL	T	3.8	14.45	10.73	74

City		Type	Size (sq m)	Conventional Fuel Use (M̄Btu)	Net Fuel Displaced (M̄Btu)	% Solar Fraction
New Orleans	LA	T	3.8	14.22	10.61	75
New York	NY	Gs	3.8	17.68	11.22	63
Newark	NJ	Gr	4.5	17.78	10.33	58
Norfolk	VA	W	3.8	16.44	10.74	65
Oakland	CA	T	3.8	16.93	12.36	73
Omaha	NE	S	3.0	18.88	10.58	56
Orlando	FL	T	3.0	13.37	9.76	73
Philadelphia	PA	Gr	3.8	17.61	9.56	54
Pittsburgh	PA	Gr	3.8	18.63	8.83	47
Portland	OR	W	3.8	18.09	8.88	49
Raleigh	NC	Gs	3.8	16.49	11.43	69
Rapid City	SD	S	3.0	19.57	11.00	56
Reno	NV	S	3.0	18.90	12.73	67
Roanoke	VA	Gs	3.8	17.27	11.69	68
St Louis	MO	Gr	3.8	16.82	10.31	61
Salt Lake City	UT	S	3.0	18.48	11.64	63
San Antonio	TX	T	2.3	14.09	8.95	64
San Diego	CA	T	3.8	15.57	12.50	80
Seattle	WA	W	3.0	18.47	7.36	40
Shreveport	LA	W	3.8	14.81	10.33	70
Springfield	MO	Gr	3.8	16.77	10.50	63
Syracuse	NY	S	3.8	19.20	9.47	49
Tucson	AZ	W	3.0	14.34	10.61	74
Tulsa	OK	Gr	3.8	16.22	10.32	63
Washington	DC	Gs	3.8	17.82	11.22	63
Wichita	KS	S	3.8	17.10	11.89	70

NOTES:

a - D - drainback
Gr- glycol, regular surface
Gs- glycol, selective surface
S - silicone
T - thermosyphon
W - draindown

b - excluding pilot light use: 3.1 - 3.5 M̄Btu/year

APPENDIX C-3. Annualized Costs and Savings for Solar/Electric Systems

City		Costs: Operation	Costs: Maintenance	Costs: Capital	Savings: Fuel	Savings: Taxes	Savings: Net
Albuquerque	NM	$57	$76	$462	$336	$384	$ 125
Amarillo	TX	54	73	462	257	283	- 50
Atlanta	GA	22	67	363	239	227	15
Augusta	ME	59	84	505	334	321	7
Bakersfield	CA	33	62	327	235	249	62
Baltimore	MD	31	88	427	255	260	- 31
Birmingham	AL	18	64	363	218	271	44
Bismarck	ND	50	89	505	267	387	10
Boise	ID	28	73	462	230	328	- 6
Boston	MA	82	91	598	320	565	114
Burlington	VT	51	99	598	288	512	53
Casper	WY	30	77	462	268	275	- 26
Charleston	WV	24	84	427	220	266	- 49
Charlotte	NC	21	76	363	217	306	64
Chicago	IL	69	72	462	288	278	- 38
Columbia	SC	20	66	363	232	227	10
Columbus	OH	38	100	427	250	294	- 21
Dallas	TX	20	58	363	213	222	- 6
Denver	CO	44	74	462	311	413	143
Des Moines	IA	68	82	505	272	331	- 53
Detroit	MI	54	101	427	352	291	62
Duluth	MN	49	105	598	298	504	51
Durango	CO	52	73	462	328	413	153
El Paso	TX	24	89	327	240	200	- 1
Evansville	IN	41	70	462	223	379	28
Ft Wayne	IN	34	79	505	234	414	30
Fresno	CA	36	63	327	238	249	61
Hartford	CT	68	80	505	303	289	- 61
Helena	MT	46	77	462	282	310	6
Honolulu	HI	10	50	327	321	239	173
Houston	TX	7	48	327	248	200	67
Jackson	MS	18	57	363	212	219	- 7
Jacksonville	FL	6	48	327	264	200	83
Knoxville	TN	14	73	363	197	214	- 39
Las Vegas	NV	14	112	363	195	215	- 80
Lexington	KY	25	87	427	221	262	- 56
Little Rock	AR	25	78	327	202	222	- 2
Los Angeles	CA	6	48	327	304	249	171
Madison	WI	50	83	505	265	355	- 18
Medford	OR	37	77	505	238	437	56
Memphis	TN	15	72	363	208	214	- 28
Miami	FL	7	48	327	276	200	129a
Mobile	AL	4	48	327	213	244	77
New Orleans	LA	5	48	327	214	201	35

City		Costs Operation	Costs Maintenance	Costs Capital	Savings Fuel	Savings Taxes	Savings Net
New York	NY	$77	$88	$455	$409	$362	$ 151
Newark	NJ	46	92	455	331	271	8
Norfolk	VA	21	73	363	214	307	64
Oakland	CA	8	48	327	298	249	164
Omaha	NE	38	82	505	274	427	75
Orlando	FL	6	48	327	245	200	64
Philadelphia	PA	49	92	455	295	268	- 33
Pittsburgh	PA	42	104	455	236	268	- 97
Portland	OR	24	73	455	203	394	44
Raleigh	NC	31	83	455	256	388	75
Rapid City	SD	50	76	462	258	272	- 58
Reno	NV	63	77	462	379	269	44
Roanoke	VA	31	87	455	275	385	87
St Louis	MO	43	65	427	226	263	- 46
Salt Lake City	UT	67	75	462	349	332	76
San Antonio	TX	6	51	327	243	200	59
San Diego	CA	12	49	327	340	249	202
Seattle	WA	12	87	470	183	275	- 110
Shreveport	LA	19	54	363	208	223	- 5
Springfield	MO	45	65	427	214	263	- 61
Syracuse	NY	40	80	505	236	401	11
Tucson	AZ	46	77	462	261	435	110
Tulsa	OK	24	81	398	258	375	130
Washington	DC	42	99	455	326	289	18
Wichita	KS	52	80	505	302	458	123

NOTE:
a - includes rebate by electric utility, about 12% of investment

APPENDIX C-4. Annualized Costs and Savings for Solar/Gas Systems

City		Costs Operation	Maintenance	Capital	Savings Fuel	Taxes	Net
Albuquerque	NM	$52	$67	$427	$140	$354	$ - 52
Amarillo	TX	35	93	377	120	231	- 154
Atlanta	GA	22	60	327	104	205	- 101
Augusta	ME	61	76	462	196	294	- 110
Bakersfield	CA	33	62	327	119	249	- 55
Baltimore	MD	29	86	434	135	264	- 150
Birmingham	AL	18	64	363	116	271	- 59
Bismarck	ND	50	81	462	157	354	- 83
Boise	ID	28	73	462	161	328	- 75
Boston	MA	54	96	455	143	430	- 32
Burlington	VT	50	83	505	133	433	- 72
Casper	WY	28	70	427	165	254	- 106
Charleston	WV	24	84	427	138	266	- 131
Charlotte	NC	21	76	363	125	306	- 28
Chicago	IL	64	67	427	109	257	- 192
Columbia	SC	21	60	327	112	204	- 91
Columbus	OH	56	66	427	114	294	- 140
Dallas	TX	21	51	327	112	200	- 87
Denver	CO	44	74	462	159	413	- 10
Des Moines	IA	66	68	427	132	279	- 150
Detroit	MI	54	101	427	140	291	- 150
Duluth	MN	48	88	505	155	426	- 60
Durango	CO	52	73	462	147	413	- 28
El Paso	TX	24	89	327	115	200	- 126
Evansville	IN	24	87	434	113	355	- 77
Ft Wayne	IN	35	72	462	120	379	- 70
Fresno	CA	36	63	327	114	249	- 63
Hartford	CT	65	67	427	122	244	- 193
Helena	MT	43	71	427	128	286	- 127
Honolulu	HI	10	50	327	182	239	+ 34
Houston	TX	7	45	306	96	187	- 74
Jackson	MS	18	52	327	100	198	- 100
Jacksonville	FL	6	48	327	130	200	- 51
Knoxville	TN	15	66	327	102	202	- 104
Las Vegas	NV	16	88	327	105	194	- 132
Lexington	KY	23	86	434	127	267	- 149
Little Rock	AR	24	78	327	104	222	- 104
Los Angeles	CA	6	48	327	162	248	+ 29
Madison	WI	52	76	462	154	325	- 111
Medford	OR	23	81	434	133	375	- 29
Memphis	TN	15	65	327	99	189	- 119
Miami	FL	7	45	306	113	187	- 58
Mobile	AL	4	48	327	124	244	- 11
New Orleans	LA	5	48	327	131	201	- 48

City		Costs: Operation	Costs: Maintenance	Costs: Capital	Savings: Fuel	Savings: Taxes	Savings: Net
New York	NY	$77	$83	$427	$165	$339	$ - 82
Newark	NJ	42	86	434	133	259	- 171
Norfolk	VA	21	73	363	130	307	- 20
Oakland	CA	8	48	327	143	249	+ 9
Omaha	NE	36	69	427	121	361	- 50
Orlando	FL	6	45	306	116	187	- 53
Philadelphia	PA	45	80	406	118	238	- 175
Pittsburgh	PA	39	92	406	108	238	- 190
Portland	OR	16	68	363	107	314	- 27
Raleigh	NC	31	77	427	142	364	- 30
Rapid City	SD	46	70	427	141	251	- 150
Reno	NV	63	70	427	166	248	- 146
Roanoke	VA	31	82	427	159	361	- 20
St Louis	MO	26	83	406	124	250	- 140
Salt Lake City		62	68	427	129	306	- 122
San Antonio	TX	6	42	285	93	174	- 65
San Diego	CA	12	49	327	149	249	+ 10
Seattle	WA	13	60	327	85	192	- 124
Shreveport	LA	19	54	363	109	223	- 103
Springfield	MO	27	83	406	114	250	- 152
Syracuse	NY	42	73	462	120	367	- 90
Tucson	AZ	22	71	327	116	308	+ 4
Tulsa	OK	22	75	406	107	382	- 14
Washington	DC	42	93	427	161	271	- 130
Wichita	KS	53	72	462	133	419	- 35

APPENDIX C-5. Measures of Temperature Stress, by City

City	Cold Stress	Heat-Stress Elec.	Heat-Stress Gas	City	Cold Stress	Heat-Stress Elec.	Heat-Stress Gas
Albuquerque	2356	255.5	139.1	Little Rock	911	0	0
Amarillo	2695	121.2	39.6	Los Angeles	0	.9	.9
Atlanta	368	0	0	Madison	7096	4.5	1.0
Augusta	7490	0	0	Medford	1317	57.1	9.5
Bakersfield	29	25.5	25.5	Memphis	518	.1	0
Baltimore	2053	.1	.4	Miami	0	1.1	.1
Birmingham	294	0	0	Mobile	0	0	0
Bismarck	11163	27.7	24.2	New Orleans	0	.2	.2
Boise	2720	104.6	104.6	New York	1515	10.3	10.3
Boston	2380	14.5	4.5	Newark	2045	3.4	.2
Burlington	7264	8.1	.3	Norfolk	543	0	0
Casper	6770	65.7	30.8	Oakland	0	0	0
Charleston	1891	2.2	2.2	Omaha	5538	44.1	6.0
Charlotte	605	0	0	Orlando	0	.6	0
Chicago	3775	4.9	.6	Philadelphia	2037	3.6	0
Columbia	354	0	0	Pittsburgh	3179	.6	0
Columbus	3308	3.1	0	Portland	408	2.3	0
Dallas	77	2.9	1.0	Raleigh	945	13.4	13.4
Denver	5073	46.3	46.3	Rapid City	7125	12.8	3.9
Des Moines	5472	40.6	4.5	Reno	5142	163.3	86.5
Detroit	3432	2.4	2.4	Roanoke	1566	6.2	6.2
Duluth	11068	6.7	.6	St Louis	2171	4.4	2.1
Durango	3114	102.9	102.9	Salt Lake City	3762	140.0	74.0
El Paso	769	29.3	29.3	San Antonio	0	7.9	0
Evansville	2091	6.1	1.9	San Diego	0	1.2	1.2
Ft Wayne	3845	6.5	1.8	Seattle	370	.7	0
Fresno	107	21.4	21.4	Shreveport	15	.6	.6
Hartford	4432	.5	0	Springfield	2236	63.7	1.9
Helena	7870	12.5	4.1	Syracuse	4492	.7	.1
Honolulu	0	3.6	3.6	Tulsa	1302	12.6	5.7
Houston	0	.4	0	Tucson	8	478.4	42.4
Jackson	111	0	0	Washington	2600	6.0	6.0
Jacksonville	0	.3	.3	Wichita	2598	115.2	67.6
Knoxville	550	0	0				
Las Vegas	390	77.9	50.1				
Lexington	1979	6.8	4.5				

Note: See Equations 45 and 46 in Appendix D for a formal derivation of the cold and heat stress indices. See pages 36-37 and 42-44 for a discussion of the reasons for their use.

APPENDIX D. Formal Description of the Engineering Model

The engineering model operates for a chosen collector-storage system, in each city, each month, for a representative day that month. It operates every hour or half hour during 24 hours to model 1) sun angle, 2) insolation on the collector --- beam, diffuse, and reflected, 3) heat collected, and lost in transport, 4) changes in stored heat energy, 5) fuel use for heat, 6) operating energy, and 7) measures of temperature stress.

The model uses average climate data for a month. Therefore the net change in stored energy over 24 hours is constrained to be negligible. The calculation of useful solar energy begins with computing fuel needed to heat hot water each month in a conventional water heater. The useful solar energy collected, or fuel displaced, is the fuel used in a conventional water heater, less that used in the solar/backup system.

The engineering model can be described in 46 equations comprising seven sections. As written, these describe a system containing a solar storage preheat tank and a (smaller) conventional fuel hot water heater. A single tank system can be described without Equations 32-35 and by changing some subscripts referring to a second tank. The seven sections are

1. Engineering Parameters Constant over Time

The chief objective of this section is to determine F_R, the fraction of heat induced by the solar radiation which is removed in the collector fluid. Equation 1 is used in Equation 2, which is used in Equation 3.[1]

$$(1) \quad \eta_f = \frac{\tanh M}{M} \qquad \text{where} \quad M = \frac{\ell - d}{2} \sqrt{\bar{U}_c/(kt)}$$

η_f is the fin efficiency, for heat transfer from the black absorber plate (fins) to the tubes embedded in the plate. $\frac{\ell - d}{2}$ is the maximum distance on the plate from a tube, where d is a tube's outside diameter and ℓ is the center-to-center spacing between parallel tubes. $\bar{U}_c$ is the weighted (by heat collected) mean thermal conductance of the collector to its surroundings, per unit collector area (see Eqs. 27). The absorber plate's thermal conductivity is k and its thickness is t .

$$(2) \quad F' = \frac{1 / (\bar{U}_c * \ell)}{1/ \{\bar{U}_c*(d + \eta_f*[\ell-d])\} \; + \; 1/\{\pi * \bar{h} * d\}}$$

F' is called the collector efficiency factor, the ratio of two thermal resistances: that between the collector surface and the air, and that between the fluid and its immediate surroundings. Again, $\bar{U}_c$ is the collector's average thermal conductance, ℓ is the tube spacing, and d is the tube diameter. η_f is the fin efficiency from Eq. 1. The average film heat transfer coefficient for convection by water in turbulent flow is $\bar{h}$.

$$(3) \quad F_R = \frac{G*c_p}{\bar{U}_c} * [\ 1 - \exp\ (\frac{-F'*\bar{U}_c}{G * c_p})\ ]$$

F_R is called the heat removal factor, and adjusts for the fact that the absorber plate is not uniform in temperature. G is the fluid's flow rate per unit of net (glass) collector area, c_p is the fluid's specific heat, $\bar{U}_c$ again is the collector's mean conductance, and F' is the collector efficiency factor from Eq. 2.

$$(4) \quad U_p = \pi * d_p * \ell_p * H_p$$

U_p is the thermal conductance of the pipes connecting the collector with storage, measured in Watts/°K. The diameter of those pipes is d_p, the length of the pipes is ℓ_p, and H_p is the thermal conductance of the pipes plus their insulation, per unit area of pipe.

$$(5) \quad U_b = H_b * (A + 2 A_b + A_s) / A$$

U_b is the thermal conductance of the collector's back and sides. H_b is the average thermal conductance of the insulation there. A is the (net) area of the glass on top, A_b is the area of the top border around the glass, and A_s is the surface area of the four sides.

2. Initial Calculations for City and Monthly Loops

The objectives of this section are to determine 1) temperatures of the cold water supply and the space surrounding the storage tanks, 2) fuel use in a conventional water heater, and 3) numbers used often in the hourly loop.

$$(6) \quad I_0 = 1353 \frac{\text{Watts}}{\text{sq m}} * (1 + .034*\cos [\frac{360°*n}{365}])$$

The solar constant, 1353 $\frac{\text{Watts}}{\text{sq m}}$, is adjusted for the elliptical shape of Earth's orbit. The day of the year is n . (February 15 = 46)

$$(7) \quad R_d = \cos^2 (\beta/2)$$

The diffuse tilt factor R_d is a function of the collector's tilt from the horizontal, angle β . The equation assumes diffuse radiation is isotropic.

$$(8) \quad T_g = .6\,\bar{\bar{T}}_a + .12\,\bar{T}_a + .28\,\bar{T}_{a,\,mo-1}$$

The month's average cold water supply temperature T_g is assumed about equal to the ground temperature a few feet down. $\bar{\bar{T}}_a$, $\bar{T}_a$, and $\bar{T}_{a,mo-1}$ are the respective mean temperatures for the year, the month, and the previous month, for a particular city.

$$(9) \quad T_b = 291°K + (\bar{T}_a - \bar{\bar{T}}_a)/4$$

The (basement) temperature surrounding the storage tank(s) averages 64°F and varies by several degrees over the year.

$$(10) \quad Q'_d = \frac{g_{mo}*(T_s - T_g) + (24\text{ hr})*F_1*(T_s - T_b)}{\eta_{ff}} * 1.1628\,\frac{\text{W-hr}}{\text{Cal}}$$

A day's fuel use in a conventional water heater is Q'_d. The heat transfer efficiency from conventional fuel to stored water is η_{ff} ; heat not transferred to the water goes up the flue or heats the metal tank. T_s , T_g, and T_b are the respective temperatures of hot tap water, the cold water supply, and the basement surrounding the storage tank(s). F_1 is a heat loss factor for the hot water tank, based on its surface area and insulation. The quantity of hot tap water used in a day that month is g_{mo}.

(11) $R_{r,mo} = \rho_{mo} * \cos^2(\beta/2)$

$R_{r,mo}$ is the reflection tilt factor. The estimated[2] average reflectance of the collector's surroundings that month is ρ_{mo}, and β is the collector's tilt angle from the horizontal.

(12) $\bar{K}_{mo} = \frac{1374}{1353} \bar{K}_T$

The average clearness over a month in a place, compiled by Knapp et al.[3], is adjusted as they suggest to compensate for an erroneous previous estimate of the solar constant. $\bar{K}_T$ is the compiled value and $\bar{K}_{mo}$ is the true value.

(13) $SR = -SS = \cos^{-1}(-\tan L * \tan \delta_{mo})$

The angles (east = 90° and south = 0°) at which the sun rises and sets are a function of the latitude L and the sun's current declination δ_{mo}.[4]

3. Insolation and Air Temperature at Time t

The chief objectives of this section are to estimate the power of insolation on the collector at a particular moment and the ambient air temperature at that moment. First, the angle of the sun and the sky's estimated clearness are used to compute the sun's estimated power on a level surface ($I_{h,t}$). Then the three components of radiation --- beam or direct, diffuse or refracted, and reflected --- are multiplied by tilt factors and summed to yield the sun's power on a tilted collector surface.

$$(14) \quad \sin \alpha_t = \sin \delta_{mo} * \sin L + \cos \delta_{mo} * \cos L * \cos \omega_t$$

The angle the sun makes with a horizontal surface at some moment is α_t.[5] The solar declination for the day is δ_{mo}, the city's latitude is L, and the time in angular form is ω_t. (10 AM = 30° and 1 PM = -15°)

$$(15) \quad R_{b,t} = \frac{\sin \delta_{mo} * \sin(L-\beta) + \cos \delta_{mo} * \cos(L-\beta) * \cos \omega_t}{\sin \alpha_t}$$

$R_{b,t}$ is the beam tilt factor at a given moment. The sun's declination for the month is δ_{mo}, the city's latitude is L, the collector tilt is β, the time in angular form is ω_t, and α_t is the sun angle from Eq. 14.

$$(16) \quad I_{h,t} = \max\,(0,\ I_0 * \bar{K}_{mo} * \sin \alpha_t)$$

Insolation at time t on a horizontal surface at ground level is a function of the solar "constant" I_0, the "clearness" (approximated by the mean monthly clearness $\bar{K}_{mo}$), and the sun angle α_t.

$$(17) \quad I_{d,t} = I_{h,t} * (1.390 - 4.027\,\bar{K}_{mo} + 5.531\,\bar{K}_{mo}^{2} - 3.108\,\bar{K}_{mo}^{3})$$

Diffuse insolation $I_{d,t}$ on a horizontal surface is given by the Liu-Jordan regression.[6] Total insolation $I_{h,t}$ is from Eq. 16 and $\bar{K}_{mo}$ is the average monthly clearness from Eq. 12.

(18) $I_{b,t} = I_{h,t} - I_{d,t}$

Beam insolation $I_{b,t}$ is total insolation $I_{h,t}$ less diffuse insolation.

(19) $I_{c,t} = I_{b,t} * R_{b,t} + I_{d,t} * R_d + I_{h,t} * R_{r,mo}$

$I_{c,t}$ is the total power of insolation on the collector per unit area. $I_{b,t}$, $I_{d,t}$, and $I_{h,t}$ come from Eqs. 18, 17, and 16 respectively. $R_{b,t}$, R_d, and $R_{r,mo}$ are the respective tilt factors from Eqs. 15, 7, and 11. $R_{r,mo}$ contains ρ_{mo}, which adjusts total insolation $I_{h,t}$ to get reflected insolation $I_{r,t}$.

(20) $T_{a,t} = \bar{T}_{min} + (\bar{T}_{max} - \bar{T}_{min}) * \sin (M * [SR - \omega_t]/[SR - SS])$ by day,

(20a) $\quad = \bar{T}_{min} + (\bar{T}_{max} - \bar{T}_{min}) * \sin M * (\frac{SR - \omega_t}{SR - SS - 360°})$ till dawn,

(20b) $\quad = \bar{T}_{min} + (\bar{T}_{max} - \bar{T}_{min}) * \sin M * (\frac{SR - \omega_t - 360°}{SR - SS - 360°})$ after sunset.

where $\quad M = \dfrac{1800°}{13 + \sin (n°/2)}$

$T_{a,t}$ in Eqs. 20, 20a, and 20b is the estimated[7] ambient air temperature at time t. Eq. 20 estimates the temperature between sunrise and sunset, followed by Eq. 20b from sunset to midnight and Eq. 20a from midnight to dawn. Thus, estimated temperature follows a sinusoidal form by day, but drops linearly during the night. $\bar{T}_{min}$ and $\bar{T}_{max}$ are the month's average daily low and high temperatures. SR and SS, from Eq. 13, are the angles at which the sun rises and sets. The time in angular form is ω_t and n is the day of the year. Note the low temperature is at sunrise.

4. Solar Heat Collection and Solar Heat Storage

Since the model uses average weather data for one day a month, on average the change in heat stored over a day should be small. Also, heat collection and storage temperatures determine each other interactively. So a set of iterations continues for 24 hours until the change in storage temperature over 24 hours is less than .2°K. (See Eq. 41.) The loop begins by assuming the temperature in the solar storage tank is the same as the basement's, the temperature in the backup tank is at the thermostat set point, the temperatures of the air and the collector are the same, and the sun was not up at midnight. The usual iteration period is half an hour.

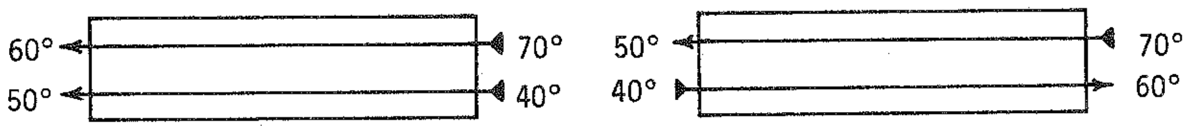
$$(21) \quad T_{c,t} = 1°K + T_{st1,t-1} + \Delta T_{f,t-1} * \left(\frac{1}{\eta_x} - .5\right) + \frac{L_{p,t-1}}{A * G * \Delta t * 4186\ J/Cal}$$

$$(21a) \quad = T_{c,t-1} + \frac{\Delta t}{C} * \left(\alpha_c * \tau_c * I_{c,t} - U_{c,t-1} * [T_{c,t-1} - T_{a,t}]\right)$$

Equation 21 describes the collector absorber plate temperature $T_{c,t}$ while the system pump is on. Equation 21a describes the temperature while it is off, when $q_{c,t} = 0$ (see Eqs. 28.) The plate is 1°K hotter than the fluid flowing through it. $T_{st1,t-1}$ is the temperature in the preheat tank last iteration, from Eq. 31. $\Delta T_{f,t-1}$ (Eq. 30) is an approximation for the fluid's rise in temperature as it flows through the collector. The efficiency of the heat exchanger is η_x. $L_{p,t-1}$ (Eq. 23) is the heat loss from the pipes connecting the collector with storage. A is the collector's net area, G is the fluid flow rate per unit area, and Δt is the time interval of the simulation. In Eq. 21a, $T_{c,t-1}$ is the collector temperature at the

FIGURE 14. Heat Exchangers

	A	B
Efficiency	1/3	2/3
Average Plate Temperature	66°	61°



Heat Exchanger A

Heat Exchanger B

last iteration, α_c is the absorbance of the plate, τ_c is the transmittance of the glass cover, $I_{c,t}$ is the insolation on the collector (from Eq. 19), $U_{c,t-1}$ is the collector's thermal conductance per unit area (Eq. 27), $T_{a,t}$ is the outside air temperature (Eqs. 20), Δt is the iteration time interval, and C is the thermal capacity of the collector per unit of net collector area. Most of the time that the system is not on, the sun is not up, so $I_{c,t} = 0$ and Eq. 21a simplifies.

$$(22) \quad \nabla_{p,t} = (T_{c,t} - 1°K) - (3\ T_b + T_{a,t})/4$$

$\nabla_{p,t}$ is the average temperature gradient from the pipes connecting storage with collector, to the surroundings of those pipes. The first term is the average fluid temperature and the second is the average temperature around the pipes. $T_{c,t}$, T_b , and $T_{a,t}$ are the temperatures respectively of the collector's absorber plate (Eq. 21), of the basement (Eq. 9), and of the outside air (Eq. 20).

$$(23) \quad L_{p,t} = U_p * \nabla_{p,t} * \Delta t$$

$L_{p,t}$ is the heat loss from the pipes. U_p (Eq. 4) is the thermal conductance of the pipes per degree. $\nabla_{p,t}$ (Eq. 22) is the average temperature gradient around the pipes and Δt is the simulation time interval.

$$(24)\quad L_{1,t} = F_1 * (T_{st1,t-1} - T_b) * \Delta t$$

$L_{1,t}$ is the heat loss from the solar storage tank. F_1 is a loss factor, proportional to the surface area and level of insulation. $T_{st1,t-1}$ (Eq.31) and T_b (Eq. 9) are the respective temperatures of the tank and the basement surroundings. Δt is the simulation time interval.

$$(25)\quad Q_{st1,t-1} = 1.1628\ A_1 * (T_{st1,t-1} - T_g)\ \frac{\text{W-hr}}{\text{Cal}}$$

The heat $Q_{st1,t-1}$ stored in the solar tank's hot water is a function of the volume of water stored A_1 and the temperature difference between the stored water and the cold water supply. Cold T_g is the base temperature.

$$(26)\quad q_{1,t} = g_{mo} * g_t * (T_{st1,t-1} - T_g) * \frac{T_s - T_g}{T_{st2,t-1} - T_g} * 1.1628\ \frac{\text{W-hr}}{\text{Cal}}$$

$q_{1,t}$ is the heat transferred from the preheat storage tank to the conventional water heater tank, to compensate the latter for the water drawn for end use. The fraction is the volume of hot water sent from the backup tank compared to what would be sent, if the actual backup tank temperature were the same as the set temperature T_s. The daily volume of hot water use is g_{mo} , and g_t is the fraction of that volume used in this time interval. T_s , T_g , $T_{st1,t-1}$, and $T_{st2,t-1}$ are the temperatures of hot tap water, cold water supply, water in the solar preheat tank, and water in the backup conventional water heater tank.

$$\text{(27a)}\quad U_{c,t} = U_b + \frac{310.}{14.8 + T_{c,t}*(T_{c,t} - T_{a,t})^{.31}} + \frac{3.44(T_{c,t} + T_{a,t})(T_{c,t}^2 + T_{a,t}^2)}{10^8}$$

$$\text{(27b)}\quad = U_{c,t,27a} - \frac{2.72 * (T_{c,t} + T_{a,t})\,(T_{c,t}^2 + T_{a,t}^2)}{10^8}$$

Equation 27a is for a collector with a normal black absorber surface, while 27b is for a collector with a selective absorber surface (a low infrared emissivity of about .10). The equation is a simplification from Duffie[8], assuming one ordinary glass cover, a constant wind speed of 4 meters/second and a plate emissivity of .95 (Eq. 27a) or .10 (Eq. 27b). $U_{c,t}$ must be measured in $\frac{\text{Watts}}{m^2 * {}^\circ K}$ and T's must be in °K. $U_{c,t}$ is the collector's heat conductance to the outside air. U_b (Eq. 5) is the conductance of the collector's non-glass surface. $T_{c,t}$ and $T_{a,t}$ are the temperatures of the absorber plate and of the surrounding air, from Eqs. 21 and 20. $U_{c,t,27a}$ is the $U_{c,t}$ of Eq. 27a.

$$\text{(28)}\quad q_{c,t} = \max\{\,0,\quad A*F_R*(\alpha_c*\tau_c*I_{c,t} - U_{c,t}*[T_{c,t} - T_{a,t}])\,\} \;*\; \Delta t$$

$q_{c,t}$ is the heat energy collected and transferred by the solar collector to the fluid flowing through it during the simulation time interval Δt. As long as the system operates properly, it does not heat the great outdoors (0 is a minimum). A is the net collector area. F_R (Eq. 3) is the fraction of the absorbed heat carried away by the fluid. (The rest heats up the collector.) τ_c is the fraction of incident light transmitted by the glass cover to the absorber plate[9], and α_c is the fraction of that absorbed by the plate. $I_{c,t}$ (Eq. 19) is the insolation on the collector per unit of collector area. $U_{c,t}$ (Eq. 27) is the collector's total conductance of heat to its surroundings. $T_{c,t}$ and $T_{a,t}$ are the temperatures of the absorber plate and of the ambient air.

(28a) If $T_{c,t} \leq T_{st1,t-1}$ then $q_{c,t} = 0$.

This means that the pump turns on to operate the system only when the collector is hotter than the water in solar storage.

(29) $$Q_{st1,t} = Q_{st1,t-1} + q_{c,t} - L_{p,t} - q_{1,t} - L_{1,t}$$

$Q_{st1,t}$ and $Q_{st1,t-1}$ are the heat (using cold water supply temperature T_g as a base) stored in the preheat tank, now and one iteration ago. $q_{c,t}$ (Eq. 28) is the solar energy collected and $L_{p,t}$ is the heat energy lost from pipes between collector and storage (Eq. 23). $q_{1,t}$ (Eq. 26) is the heat in the water sent from the preheat tank to the backup tank, and $L_{1,t}$ (Eq. 24) is the heat lost from the solar storage tank to its surroundings.

(30) $$\Delta T_{f,t} = \frac{q_{c,t} - L_{p,t}}{A * G * \Delta t * 4186 \text{ J/Cal}}$$

$\Delta T_{f,t}$ is the temperature decrease in the collector fluid from passing through the heat exchanger. $q_{c,t}$ (Eq. 28) is the heat collected and $L_{p,t}$ is the heat lost from pipes between collector and storage (Eq. 23). A is net collector area, G the fluid flow rate per unit area, and Δt the time interval of iteration.

(31) $$T_{st1,t} = T_g + \frac{Q_{st1,t}}{1.1628 * A_1 \text{ W-hr/Cal}}$$

$T_{st1,t}$ is the updated storage temperature in the preheat tank and T_g is the base temperature,of the cold water supply. $Q_{st1,t}$ (Eq. 29) is the heat in storage there and A_1 is the quantity of water stored there.

5. Conventional Backup Water Heater and Storage

The equations are similar to those in the preceding section, with two main differences. Heat is added from the solar tank, not the collector. Heat can also be added from the backup fuel, <u>if</u> the backup tank's temperature falls below the thermostat set temperature, modelled by Eqs. 36-39.

$$(32) \quad L_{2,t} = F_2 * (T_{st2,t-1} - T_b) * \Delta t$$

$L_{2,t}$ is the heat loss from the conventional backup tank and the pipes connecting it to the preheat tank. F_2 is a heat loss factor, a function of the surface area of the tank (and pipes) and the insulation level(s). The water temperature in the backup heater is $T_{st2,t-1}$ (Eq. 35 or 39) and the basement temperature is T_b. Δt is the iteration time interval.

$$(33) \quad q_{2,t} = 1.1628 * g_{mo} * g_t * (T_s - T_g) \frac{\text{W-hr}}{\text{Cal}}$$

$q_{2,t}$ is the heat drawn from the backup tank, to be used for showers and so forth. g_{mo} and g_t are the average daily volume of water use and the fraction used during this iteration. T_s and T_g are the hot and cold tap water temperatures (thermostat set and water supply temperatures). Implicit in the equation is a corresponding reduction in quantity drawn for any increase in backup water temperature above the set point, by use of a mixing valve between the water heater and the hot tap water supply.

(34) $Q_{st2,t} = Q_{st2,t-1} + q_{1,t} - q_{2,t} - L_{2,t}$

$Q_{st2,t}$ and $Q_{st2,t-1}$ are the heat energy stored in the backup water heater, now and one iteration ago. The heat received from the preheat tank is $q_{1,t}$ (Eq. 26), the heat sent to end use is $q_{2,t}$ (Eq. 33), and the storage loss for the backup water heater is $L_{2,t}$ (Eq. 32).

(35) $T_{st2,t} = T_g + Q_{st2,t} / (1.1628 * A_2 \frac{W\text{-}hr}{Cal})$

$T_{st2,t}$ is the temperature of the water stored in the conventional backup water heater and T_g is the water supply temperature. $Q_{st2,t}$ is the heat stored in the water (Eq. 34) and A_2 is the volume of water in the backup tank.

<u>If</u> $T_{st2,t} > T_s$ then go to Equation 40. That is, if the water in the backup tank is already hot enough, do not go through the heat add loop.

(36) $q_{a,t} = \min \{A_2 * (T_s - T_{st2,t}) * 1.1628 \frac{W\text{-}hr}{\ell * {}^\circ K} \quad , \quad R_f * \Delta t\}$

$q_{a,t}$ is the quantity of heat added by the backup energy source. A_2 is the amount of water in the backup tank. T_s and $T_{st2,t}$ are the temperatures of hot tap water (set by the thermostat) and the water currently in the backup (conventional) tank. Δt is the iteration time interval and R_f is the rate at which the fuel supplies heat to the water in the tank.

(37) $Q_{st2,t} = Q_{st2,t\ (old)} + q_{a,t}$

Heat $q_{a,t}$ (Eq. 36) is now added to the heat already in the tank - $Q_{st2,t}$ (Eq. 34).

$$(38) \quad E_{f,t} = q_{a,t} / \eta_{ff}$$

$E_{f,t}$ is the fuel energy expended by the backup heater. $q_{a,t}$ (Eq. 36) is the heat added by the burner or coil to the stored water and η_{ff} is the net heat transfer efficiency, after flue losses and heating the tank metal.

$$(39) \quad T_{st2,t} = T_g + Q_{st2,t} / (1.1628 * A_2 \frac{\text{W-hr}}{\text{Cal}})$$

This repeats Eq. 35 for backup storage temperature, after heat is added.

From here on, control operations in the computing loop are important. The heat add loop (Eqs. 36-39) is finished, so these operations apply to all iterations, whether or not the backup water was already hot enough.

$$(40) \quad \sum_{n=t_0}^{t} E_{p,n} = P_p * M * \Delta t + \sum_{n=t_0}^{t-1} E_{p,n}$$

$E_{p,n}$ is the electrical energy to operate the system's pump(s). P_p is the pump's power consumption and Δt is the iteration time interval. $M = 1$ when the pump is on; $M = 0$ otherwise. The pump is on when $q_{c,t} > 0$. (See Eqs. 28a and 28.)

Here ends the loop which began at Eqation 21. One of three things happens. 1) If $t < t_0 + \frac{24\text{ hr}}{\Delta t}$, then time is incremented by Δt and control returns to Eq. 21. But if 24 hours have been completed, one of two things happens. 2) If $T_{st1,0} \neq T_{st1,t} \pm .2°K$, then the loop begins again at Equation 21, with sums set to zero, time $t = t_0$, and

$$(41) \quad T_{st1,0\ (new)} = T_{st1,0\ (old)} + 1.4 * [T_{st1,t} - T_{st1,0\ (old)}]$$

where $T_{st1,0\ (new)}$ is the new beginning storage temperature for this loop, based on the previous initial storage temperature $T_{st1,0\ (old)}$ for the solar storage tank, and on the solar storage tank temperature at the end of the loop just completed, $T_{st1,t}$ (Eq. 31).

3) If $T_{st1,0} = T_{st1,t} \pm .2°K$, then the iterations for the typical day in a month are finished, and monthly summaries are computed.

6. Important Monthly Summaries

Several monthly summaries are computed, two of which are output for the use of the economic model. Only one other, excess solar energy, is presented here. The model also calculates several efficiency measures, such as solar fraction.

$$(42) \quad E_{op,d} = E_{c,d} + \sum_{n=t_0}^{t_0+24/\Delta t} E_{p,n}$$

$E_{op,d}$ is the operating energy for the day. The first term is the day's operating energy for the controller and sensors. The second, the sum, is the energy used for pumping during the day. (See Eq. 40.)

$$(43) \quad Q_{s,d} = Q'_d - \sum_{n=t_0}^{t_0+24/\Delta t} E_{f,t}$$

Fossil fuel displaced - $Q_{s,d}$ - is the fuel needed for a conventional water heater (Eq. 10), less that expended by the solar backup water heater in a day (see Eq. 38).

$$(44) \quad X_{s,d} = \sum_{n=t_0}^{t_0+24/\Delta t} q_{c,t} - Q_{s,d}$$

$X_{s,d}$ is the excess solar energy collected. $\sum q_{c,t}$ is the solar energy collected over 24 hours (see Eq. 28) and $Q_{s,d}$ is gross conventional fuel displaced (Eq. 43).

7. Temperature Stress Indices

Subfreezing temperatures can cause burst pipes and broken collectors. High operating temperatures can cause a variety of problems, by speeding up corrosive chemical reactions and by differential expansion of materials. The hot and cold stress indices below give a rough measure of the stresses.

$$(45) \quad F_c = \sum_{mo=1}^{12} n_{mo} * (\max\{0 , \frac{277°K - \bar{T}_{min,mo}}{1°k}\})^{1.5}$$

F_c is the index of cold stress and n_{mo} is the number of days in a particular month. $\bar{T}_{min,mo}$ is the average daily low temperature for the month in a place. 277°K = 38.9°F = 3.84°C. F_c is the index for a particular city c.

$$(46) \quad H_c = \sum_{mo=1}^{12} n_{mo} \sum_{n=t_0}^{t_0+24/\Delta t} \frac{(\max\{340°K, T_{c,n}\} - 340°K)^2}{(1°K)^2 * (12 * 30 * 24/\Delta t)}$$

H_c is the index of heat stress and n_{mo} is the number of days in a month. $T_{c,n}$ is the temperature of the collector's absorber plate at time n, from Eq. 21. Δt is the iteration time interval. 340°K = 152.3°F = 66.84°C. H_c is the heat stress index for a particular size and design, in a particular city.

Notes for Appendix D

1. See Frank Kreith and Jan Kreider, Principles of Solar Engineering (Hemisphere Publishing, Washington, 1978), pages 203-217 for derivations of Equations 1, 2, 3, and 28. See also pages 61, 77, and 78 for derivations of Equations 6, 7, 11, and 15.

2. Estimated reflectances for each city for each month are based on this author's estimate of the proportions of greenery, snow, sand, and so forth in the vicinity of homes by time of year. They are based also on the reported reflectances of materials in Table A2.7 in Principles of Solar Engineering. Estimates range from .18 for Seattle in July with abundant dark conifers to .51 for snowbound Duluth in January. Estimates for southern cities show little variation over the year. Desert cities generally have a higher estimated albedo than places rich in vegetation.

3. Data on average monthly clearness, $\bar{K}_T$, as well as average daily low and high temperature each month in about 200 cities, are compiled by Connie L. Knapp, Thomas L. Stoffel, and Stephen D. Whittaker in the Insolation Data Manual (Solar Energy Research Institute, Golden Colorado - available from U.S. G.P.O. in Washington DC (SERI/SP-755-789), 1980). The Manual also includes insolation and other data.

4. See Kreith and Kreider, op. cit., page 60 for derivation.

5. See Kreith and Kreider, pages 45-50 for derivation.

6. See Kreith and Kreider, pages 76 ff. for a summary of Liu and Jordan's findings.

7. The estimated daily temperature profile, particularly during hours when the sun is up, is the best graphical fit to hourly temperature reports averaged over at least a twelve day period, in three different months each in 1974, in three different cities. Reporting newspapers were the Denver Post, the Minneapolis Tribune, and the St. Louis Post-Dispatch.

8. See J. A. Duffie and W. A. Beckman, Solar Energy Thermal Processes (John Wiley & Sons, New York, 1974), pages 125-135 and page 83. With large variations in wind speed as well as temperature, $U_{c,t}$ can vary by a factor of two during daylight hours. This formulation captures much of that variation.

9. The fraction of light transmitted by glass is virtually constant for angles of incidence less than 45°, which characterizes most beam insolation which affects the collector much, and most diffuse insolation. Together these usually account for over 90% of collector insolation. See Duffie and Beckman, op. cit., pages 112-117 for further details.

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4. Ray Cook (Weather Control, solar dealer) Ithaca, NY

5. Chris Dennison (Corning Sunmaster factory) Corning, NY

6. Bruce DuCharme (Capital Solar, repair history background) Denver, CO

7. Judy Green & Art Goden (dolar DHW homeowners) Ithaca, NY

8.	Nancy Gridmore (solar powered pumps)	Ft. Lauderdale, FL
9.	Peter Hess (solar homeowner)	Ithaca, NY
10.	Sally Hooks (extensive field studies and data base on solar installations at hundreds of Long Island homes)	Mineola, NY
11.	Susan Klein (background on trends, promise, & problems in solar industry)	Denver, CO
12.	Frank Luck (Sunland Solar, repair history background and numbers on achieved solar fractions in area)	Denver, CO
13.	Pam McKeever (supplied results of PSNM field study of solar/electric systems and answered follow-up questions)	Albuquerque, NM
14.	John Read (Corning Sunmaster factory)	Corning, NY
15.	David Stipanuk (Cornell U engineer, extensive questions, orientation, and suggestions on solar engineering and economics)	Ithaca, NY
16.	L. B. Townsend, Inc. (heating oil distributor)	Ithaca, NY
17.	Ray Wheaton (solar homeowner)	Newfield, NY

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6.		International Solar	
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11.	San Antonio	Grumman Energy Systems	(Noe Salinas)
12.	San Diego	Solar Energics of California	

D. Electric and Gas Utilities with Price Data

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Bakersfield	CA	Southern California Edison	(Warren Ferguson: Rosemead)
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