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Comparative Economics of Solar Thermal Central Receivers

M. J. Fish

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COMPARATIVE ECONOMICS OF SOLAR THERMAL CENTRAL RECEIVERS

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ABSTRACT

The most convincing justification for the development of the solar central receiver concept lies in its potential to compete with conventional fossil fired alternatives on strictly economic grounds. For both electrical and industrial process heat (IPH) generation, central receivers compare favorably with oil and gas, and in many cases, coal. This report presents calculational results in which the levelized energy costs from central receiver plants are compared with those from oil, gas, and coal fired plants. Both electrical and IPH applications are discussed. Uncertainties in future capital costs, fuel price escalation rates, and the underlying economic climate are included in the analysis.

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COMPARATIVE ECONOMICS OF SOLAR THERMAL CENTRAL RECEIVERS

Introduction

Proposed designs for solar central receivers have progressed through several iterations since the first major effort was undertaken for the Barstow pilot plant (refs. 1, 2). Accompanying this has been extensive materials development, prototype hardware construction and testing, and the evolution of increasingly sophisticated analytical capabilities. As a result, performance and capital cost projections for the technology can now be made with increased certainty.

Using these most recent estimates, energy costs from central receivers can be calculated and compared to conventional options in order to evaluate the potential competitiveness of the technology. This report presents such a comparison with fossil fired alternatives - oil, gas, and coal burning facilities - for both electrical and industrial process heat (IPH) generation.

Summary

Under reasonable assumptions on capital costs, economic parameters, and fuel price and escalation rates, solar central receivers appear to be competitive with oil and gas for both electrical and industrial process heat generation. Competitiveness with coal will occur, as well, provided that projected plant costs for central receivers are attained and that coal price escalation rates above inflation and/or high coal plant construction costs continue. Some of the important results discussed in this report are presented in Table I.

Levelized Energy Cost

The basis for comparison is the levelized (or discounted average) cost of energy delivered by a system over its design lifetime. It is calculated according to the equation:

$$LEC = \frac{FCR*CC_{tot} + LOM + LFC}{E_{net}}$$

where LEC = levelized energy cost;

TABLE I

SUMMARY OF LEVELIZED ENERGY COST COMPARISONS

A. Utility Applications (Capacity Factor = 50%)

	Energy Cost (Mills/kw/hr)
Oil*	100-188
Gas*	69-124
Coal*	66-106
Central Receiver**	79-105

B. Industrial Process Heat Applications (Fuel Saving)

	Energy Cost ($\$/10^6$ BTU)
Oil*	9.40 - 16.20
Gas*	5.90 - 10.15
Coal*	4.70 - 8.10
Central Receiver**	7.60 - 11.90

*Range covers fuel escalation rates of 0% to 3% above inflation

**Lower bound: baseline "nth" plant ($\$85/m^2$ heliostats)
Upper bound: lower bound + 50% increase in heliostat cost, + 100% increase in receiver, storage costs.

FCR = annual fixed charge rate on the capital investment, including the effects of taxes, tax credits, depreciation, insurance, and financing costs;

CC_{tot} = total capital cost, including interest during construction;

LOM = levelized annual operating and maintenance costs, excluding fuel cost;

LFC = levelized annual fuel cost;

E_{net} = net yearly energy production.

This equation is developed and discussed in detail in references 3 and 4. The relation of the fixed charge rate to the pertinent economic parameters is given in Appendix A and reference 5.

The approach is a particularly useful one for comparing options which differ markedly among themselves in capital investment vs. operating (i.e., fuel) expenses. It is often used by utilities in evaluating technology options (ref. 6) and also appears to be an acceptable screening device for industrial applications (ref. 7). The different operating requirements and financing structure of utilities compared to private industry, however, will lead to different values and ranges for the levelized energy cost and to slightly different conclusions in the comparison. These two potential markets will be discussed separately.

General Economic Assumptions

The underlying economic scenario assumed here is based on the author's analysis of information supplied by several private industrial firms (ref. 7) and on the historic performance of the utility financial market. Simply stated, it is observed that debt cost is normally 3-5 percentage points above the general inflation rate and that in turn, a company's return on equity is 4-6 percentage points above the cost of borrowing. Thus, the following general scenario has been used:

General inflation rate = 8%

Capital escalation rate = 8%

Debt cost = 11%

Return on equity = 15%

Other assumptions particular to a utility or private industrial company are given in the subsequent sections. Results for a second scenario in which the general inflation rate is higher are presented in Appendix B.

Electrical Generation

Capital Costs of Central Receiver Plants

Cost estimates used here assume mature designs for the solar subsystems. Heliostats are mass-produced (refs. 8-11), conventional tower construction (ref. 12) and electrical generating components (refs. 2, 13) are employed, and contingency and indirect budgets are typical of "nth" plant projects, i.e., projects involving well established construction practices (ref. 2). The results are based on a molten salt receiver and storage design (ref. 2) scaled from 100 MW_e to 300 MW_e and glass/steel heliostats of ~ 50 m^2 reflective area per unit. Instead of a single set of values, a range of costs for the solar components is considered here in order to accommodate uncertainties in the cost projections. The lower bound is the baseline "nth" plant estimate in which heliostats cost $85/$m^2$ (refs. 8-11, 14). The upper bound allows an uncertainty of +50% on heliostat cost and +100% on receiver and storage costs. A budget for interest during construction is also included. Table II summarizes the important assumptions on which the total capital costs are based.

The baseline "nth" plant of reference 2 is designed with ~ 3 hours of thermal storage, which corresponds to a capacity factor* of ~ 40% at a location similar to Barstow, CA. (Reference 15 provides guidelines for estimating levelized energy costs at other locations.) The baseline plant has been optimally redesigned (refs. 4, 5, 16) for both lower and higher capacity factors in order to compare central receivers with conventional options over the full range of operating interest to utilities: peaking ($\leq$ ~ 25% capacity factor), intermediate (~ 25% to 60% capacity factor), and base load (> ~ 60% capacity factor) applications. Figure 1 presents central receiver capital costs in $/$KW_e$ as a function of capacity factor for the assumptions of Table II. (Note the contrast in solar vs. fossil plant design with respect to capacity factor. Higher capacity factors are achieved in a solar plant by increasing the collection and storage capability of the plant. The result is higher capital costs as the capacity factor is increased. Fossil plant components, however, are sized to handle the fuel rate necessary to achieve the design power output; hence, the capital cost is roughly fixed regardless of capacity factor. In the fossil case, capacity factor increases are achieved by burning fuel for longer periods of time.)

Economic Assumptions

The important assumptions for calculating the LEC are given in Table III. These values are typical of an investor-owned utility and reflect the returns traditionally required by the financial markets. Figure 2 presents the levelized energy costs resulting from the range of values in Figure 1 and the economic scenario of Table III. Operating and maintenance (O&M) costs are derived from studies on heliostat O&M requirements (ref. 17) plus the assumption that O&M for the rest of the plant will be comparable to conventional technologies. A first-year O&M cost of 1.5% of the capital cost is escalated and discounted through the 30-year plant life.

*Capacity factor is defined as the ratio of the actual energy production from a plant to the theoretical maximum energy production (=plant power rating x8760 hrs).

TABLE II

INITIAL ASSUMPTIONS FOR CENTRAL RECEIVER CAPITAL COSTS

• Plant Description	"nth" Plant
	50 m^2 mirror area/heliostat
	Molten salt receiver/storage
	300 MW_e
• Costs	
Heliostats	\$85-\$128/m^2
Receivers/storage	Baseline (ref. 2) + 100%
Turbine/generator	\$225/kW_e
• Contingency	10%
• Indirects (construction management, fees)	15%
• Interest during construction	10%

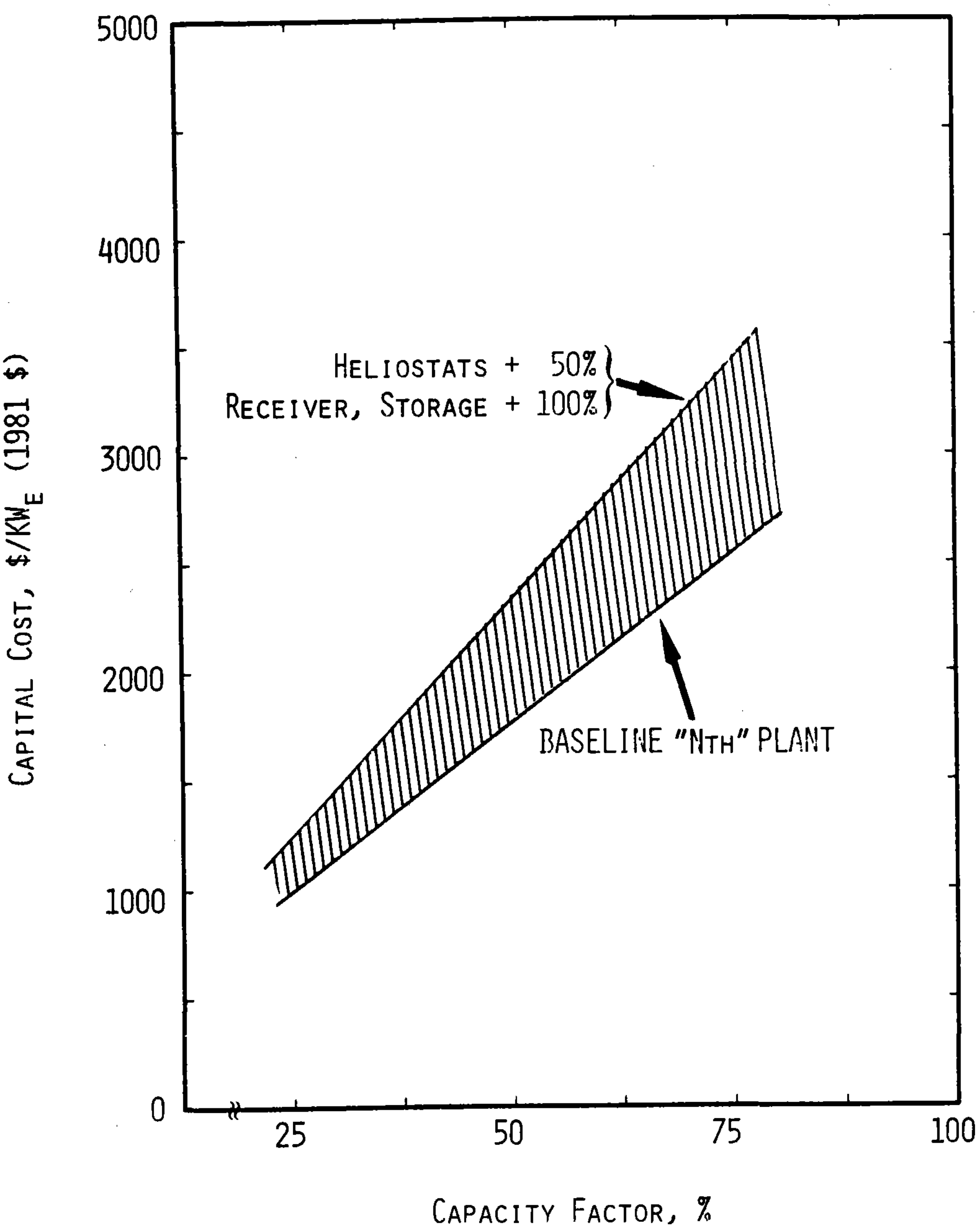

Figure 1. Capital costs of central receiver plants for electrical generation vs. capacity factor; lower bound, mature plant design with $85/m^2 heliostats; upper bound, heliostats at 50% higher cost, receivers and storage at 100% higher cost

TABLE III

ECONOMIC ASSUMPTIONS FOR INVESTOR-OWNED UTILITIES

Fixed charge rate (FCR)	15.9%	
Discount rate*		10.0%
Income tax rate		48.0%
Property tax, insurance		2.5%
Investment tax credit		10.0%
Tax life (sum-of-years digits)		24 years
Operating life		30 years
General inflation	8%	
Capital escalation	8%	
Plant start-up	1992	

*Debt fraction = 0.5
Debt cost = 11%
Fraction preferred stock = 0.1
Fraction common stock = 0.4
Rate of return (before tax) = 15%

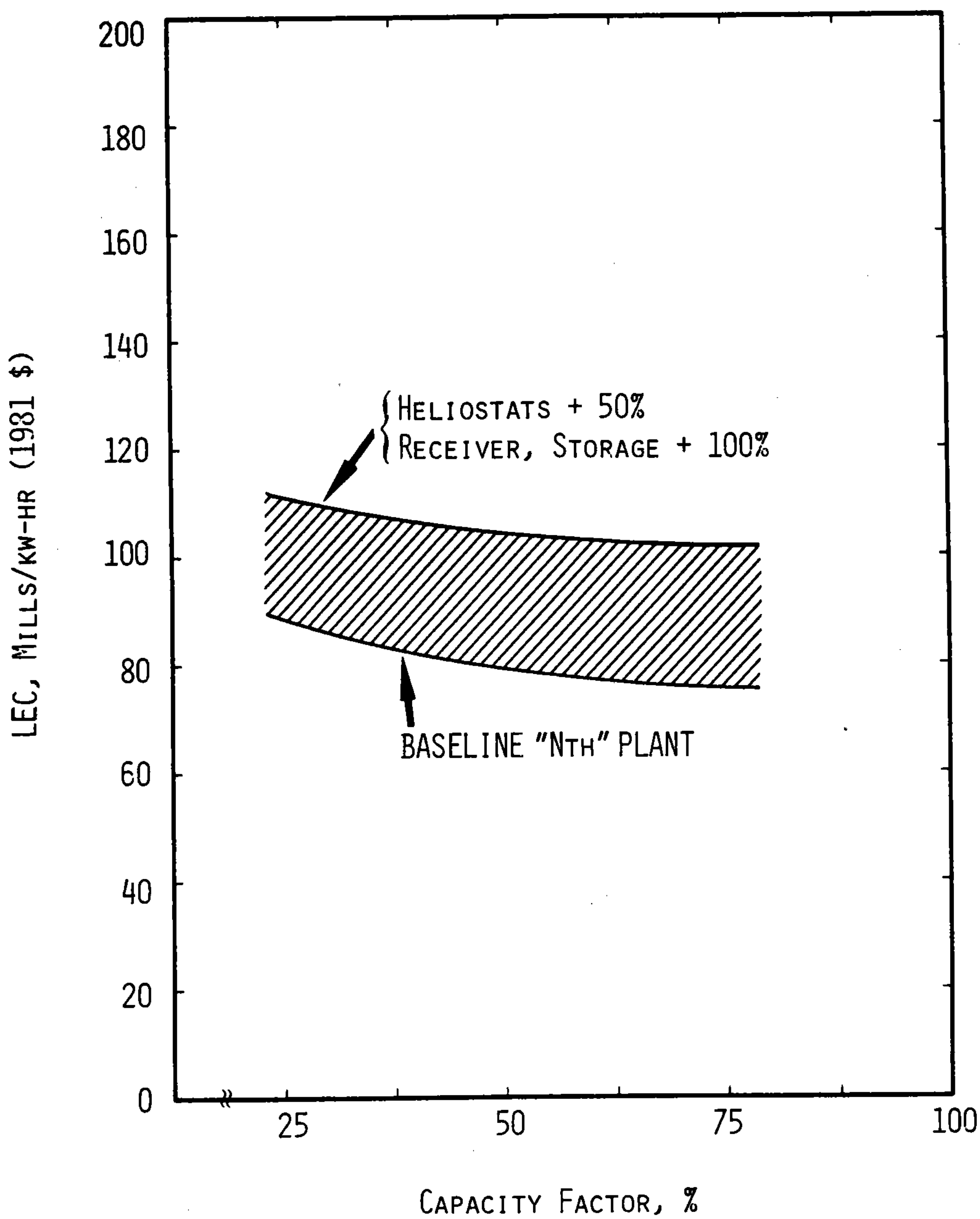

Figure 2. Levelized energy cost of mature central receivers for electrical generation vs. capacity factor.

Figure 3 is a breakdown of the lower curve in Figure 2 into its component parts. The largest direct cost contributor to the levelized energy cost is the heliostats. In addition, O&M and the add-on charges for contingency, indirects, and interest during construction comprise significant portions of the curve. Figure 3 also clearly indicates that the balance of plant is the source of the decline in energy costs as the capacity factor increases. The largest part of this category is the turbine/generator, which is a fixed capital cost item regardless of capacity factor. When this part of the capital cost is translated into an energy cost, its relative contribution will decrease with increasing capacity factor because the fixed investment is written off over the increase in annual energy production associated with increasing capacity factor.

The energy cost band of Figure 2 is duplicated on subsequent graphs where comparisons with conventional fossil fired technologies are made.

Fossil Fired Plants

The assumptions for conventional fossil fired plants are summarized in Table IV. Capital costs were obtained from the EPRI Technical Assessment Guide (ref. 18) and from conversations with a number of southwestern utilities concerning new plant costs for meeting mid 1980's emissions requirements (ref. 6). Initial fuel costs are typical of new contract prices for the delivered fuel. Uncertainties in fuel price escalation rates and geographic variations in coal plant construction costs are treated by considering a range on these parameters rather than a single value. The lower end of the range selected on fuel escalation rates represents the conservative assumption that fossil fuel prices will simply increase at the general inflation rate. The upper value of 3% above inflation is equivalent to a continuation of fuel price increases during the 1980's similar to those experienced in the previous decade (i.e., 4 to 8% annual increases over and above inflation), followed by a decline to meet general inflation in the 1990's. For illustration, such a variable fuel escalation rate scenario equivalent to the 3% above inflation case is presented in Appendix C.

TABLE IV

FOSSIL FIRED PLANT ASSUMPTIONS FOR UTILITY APPLICATIONS

	Oil	Gas	Coal
Fuel Cost (1981 $/10^6 BTU)	$4.00	$2.50	$1.50
Fuel escalation rate above inflation (%/yr)	0→3	0→3	0→3
Capital cost (1981 $/kW$_e$)	460	460	800-1600
Heat rate (BTU/kw-hr)	8600	8600	10,250

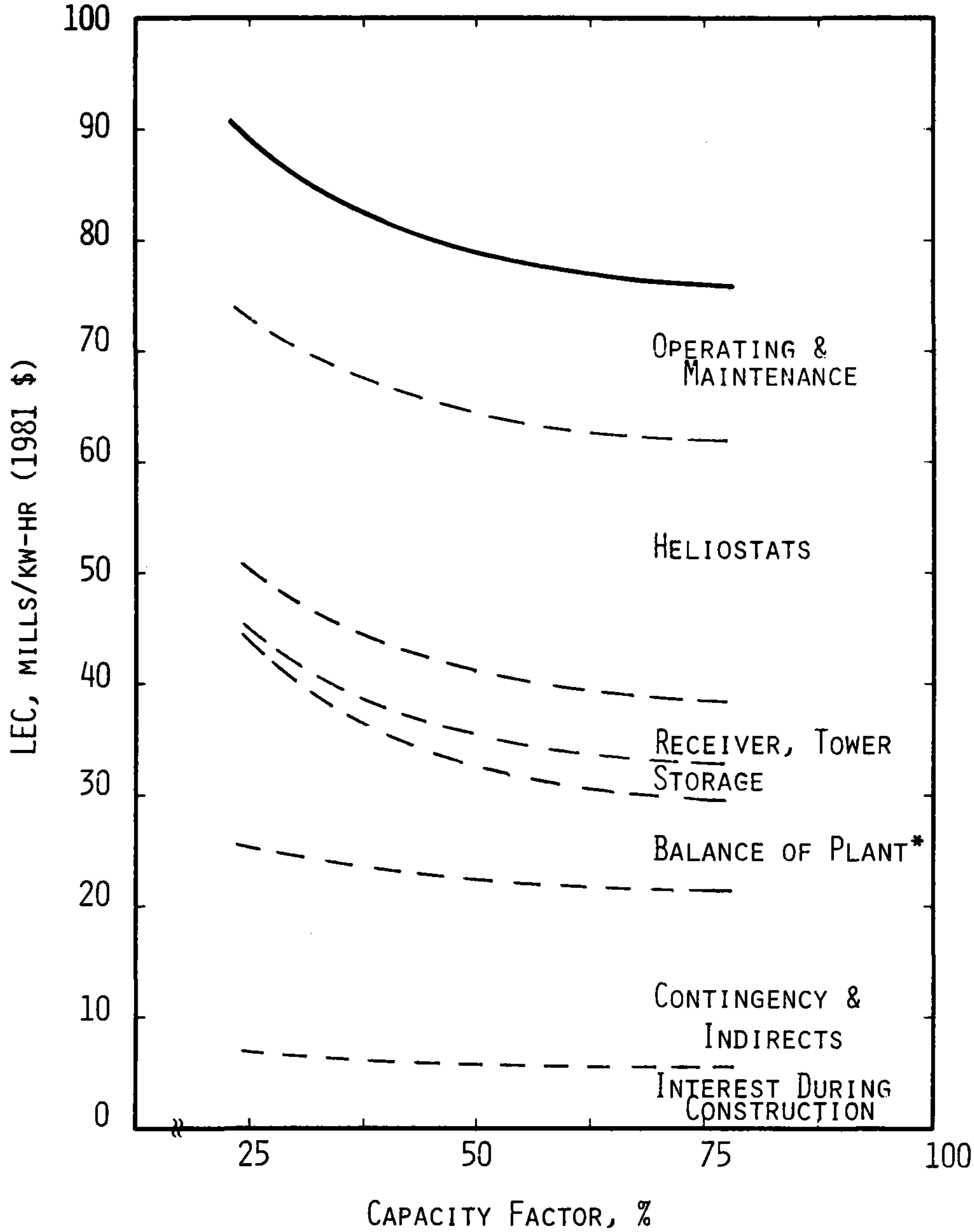

Figure 3. Levelized energy cost breakdown of lower curve of Figure 2.

*Turbine/generator, land and site preparation, buildings, switchyard, etc.

Levelized Energy Cost Comparison for Electrical Generation

Figures 4-9 present the levelized energy cost range for central receivers from Figure 2 with the energy costs from oil, gas, and coal fired plants, respectively, at the lower and upper limits of fuel escalation rate considered here. An abbreviated note in the lower right hand corner identifies each comparison. The question of allowed capacity credit* for solar is handled by presenting the fossil curves representing the extremes of 0% capacity credit (fuel displacement value only) and 100% capacity credit (fuel plus full capital value). In reality, central receivers will probably be allowed an intermediate capacity credit (refs. 19, 20).

As an example, suppose that a solar plant of 25% capacity factor would be allowed 60% capacity credit in a particular grid and would be backed up with an oil fired plant. Simply stated, this means that an oil fired plant of 40% of the capacity of the solar plant would have to be built along with the solar plant in order to insure overall grid reliability. The value of the solar plant would then be the value of the fuel it displaces (i.e., the oil which is not burned because of the solar plant power production) plus the value of the oil fired plant capacity which did not have to be built (i.e., 60% of the solar plant capacity). Disregarding any considerations of cost scaling with capacity, then one can estimate the value of the solar plant from Figure 4 (or 5) as the sum of the "fuel only" line plus 60% of the difference between the "fuel only" and "capital + fuel" curves at 25% capacity factor. In Figure 4, this amounts to ~104 mills/kw-hr. This number should then be compared to the projected cost of energy from the solar plant, which is 89-111 mills/kw-hr at 25% capacity factor. The favorable comparison of the solar plant energy cost with its value for this example of intermediate capacity credit suggests that it is a reasonable economic choice for energy production.

As seen in Figures 4 and 5, the future competitiveness of solar central receivers with oil fired plants appears certain under the most conservative of assumptions; namely, little or no capacity credit and little or no fuel price escalation above inflation. Potential competitiveness with natural gas (Figures 6 and 7) is also likely given that solar plants are allowed some capacity credit and that there is a modest escalation of gas prices above inflation or the current price is higher than used here. (Significant escalation does, in fact, appear certain. Higher current gas prices are also a reality in some areas.)

In comparing central receivers to coal (Figures 8 and 9), several points must be considered. To begin with, fuel price can vary widely, depending primarily on the proximity of the generating plant to the mine. In addition, regional variations in environmental and licensing requirements, labor productivity, and construction practices combine to produce a wide range of capital cost projections. Only one utility contacted (ref. 20) asserts future costs below $\$800/kW_e$, while another has estimated costs of $\$2750/kW_e$ for the

*Capacity credit is defined here as:

$$100\% \left(1.0 - \frac{\text{Backup capacity to meet system reliability}}{\text{Solar plant capacity}}\right)$$

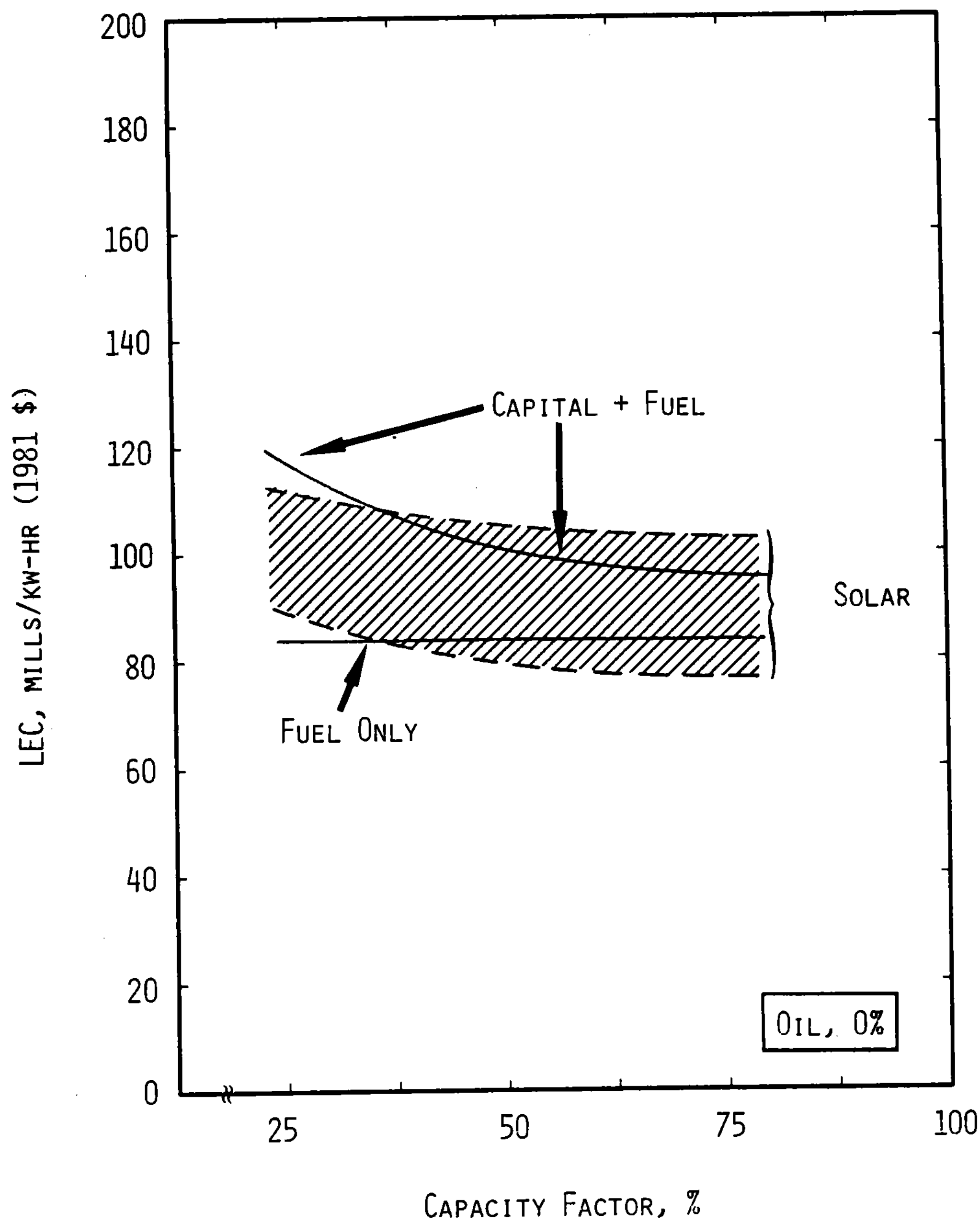

Figure 4. Energy cost comparison of central receivers and oil fired plants; 0% fuel escalation rate above inflation

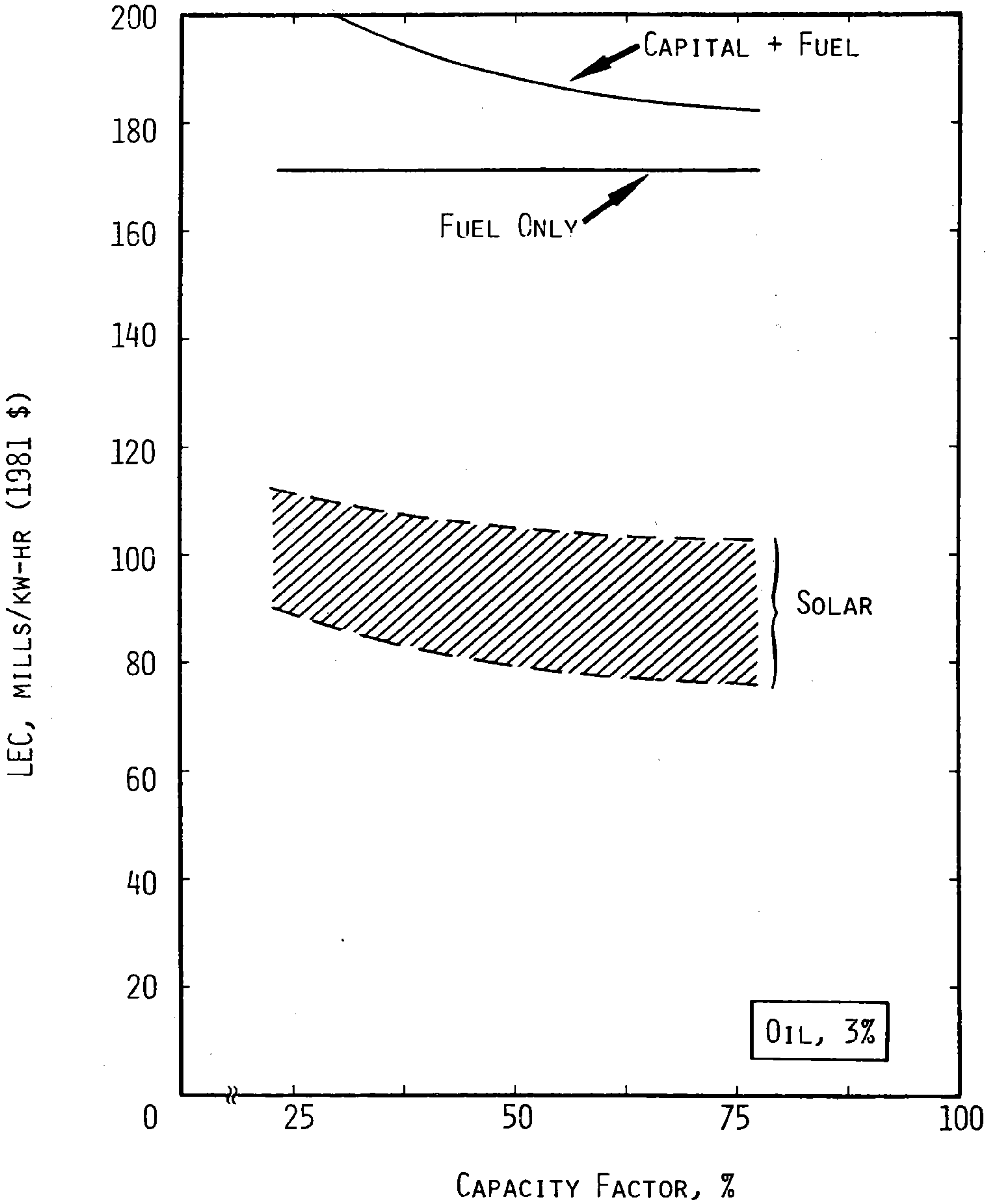

Figure 5. Energy cost comparison of central receivers and oil fired plants; 3% fuel escalation rate above inflation

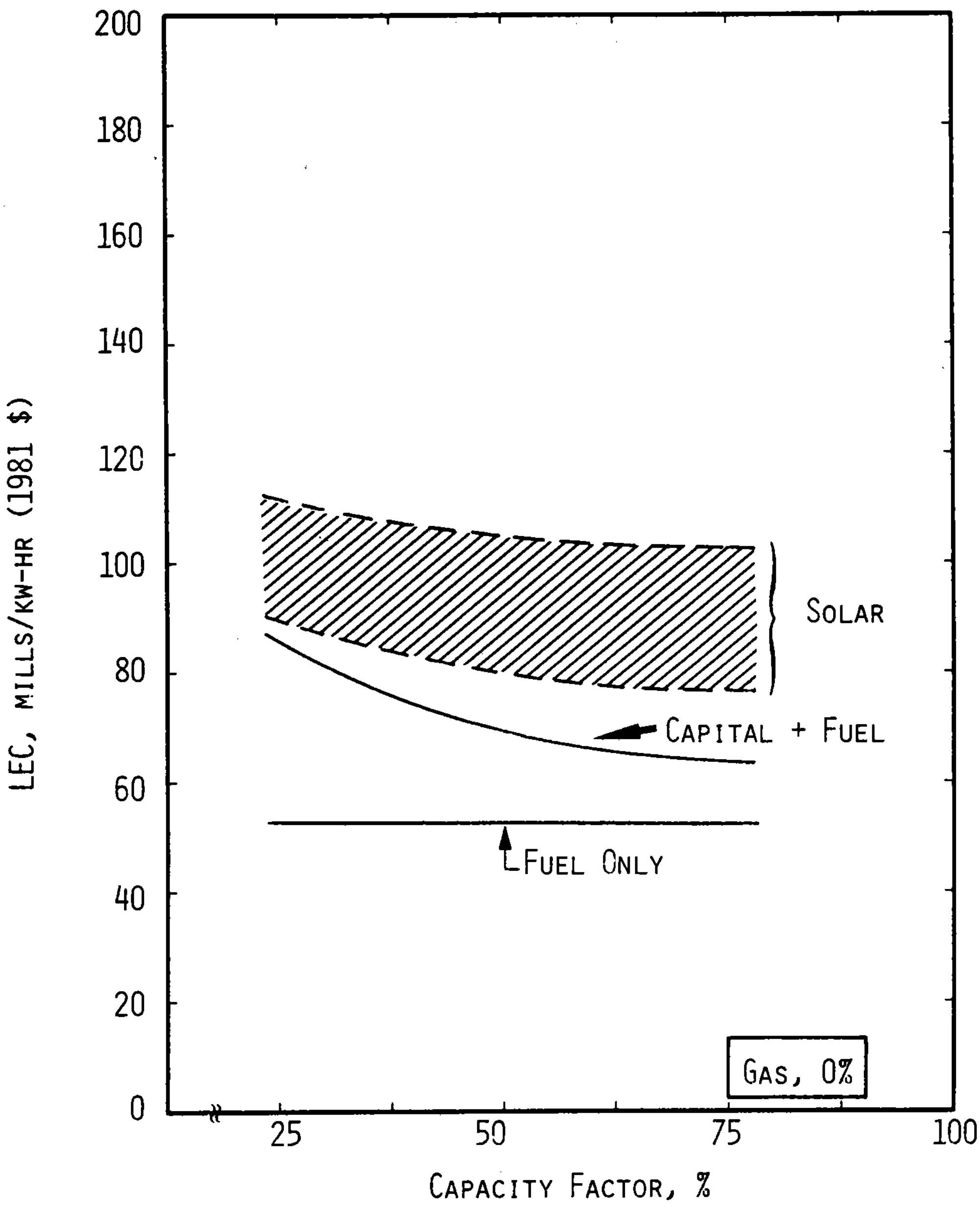

Figure 6. Energy cost comparison of central receivers and gas fired plants; 0% fuel escalation rate above inflation

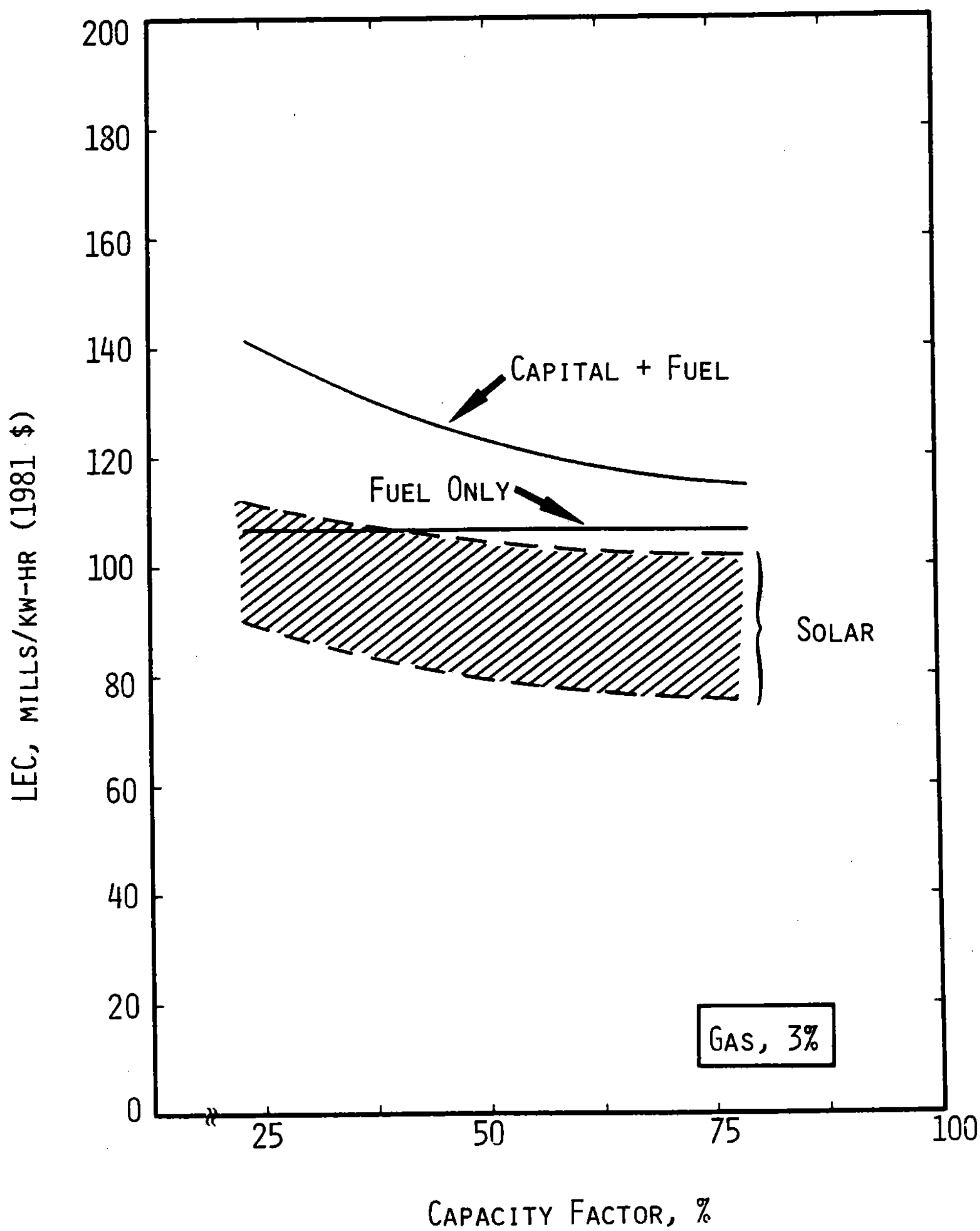

Figure 7. Energy cost comparison of central receivers and gas fired plants; 3% fuel escalation rate above inflation

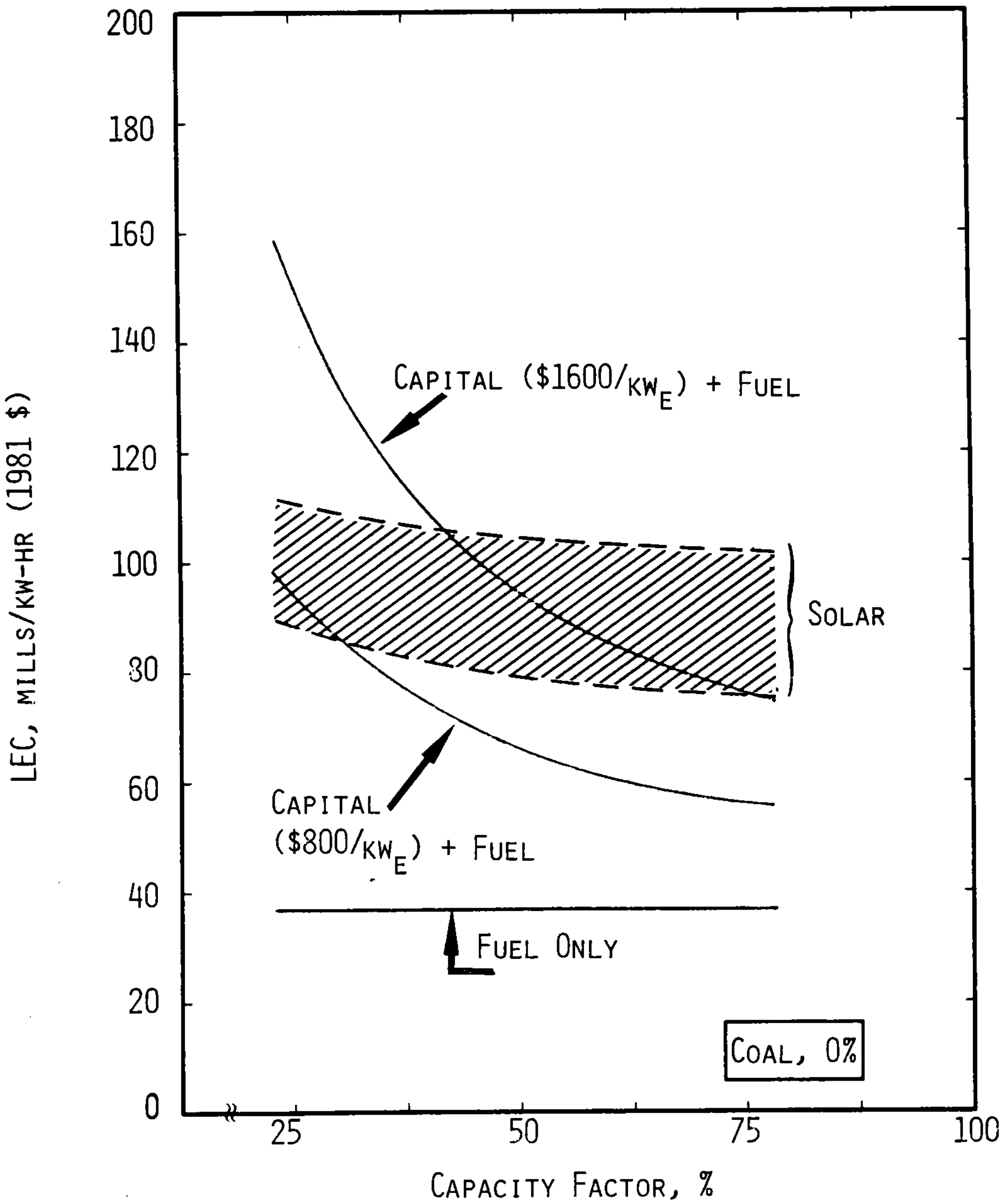

Figure 8. Energy cost comparison of central receivers and coal fired plants; 0% fuel escalation rate above inflation

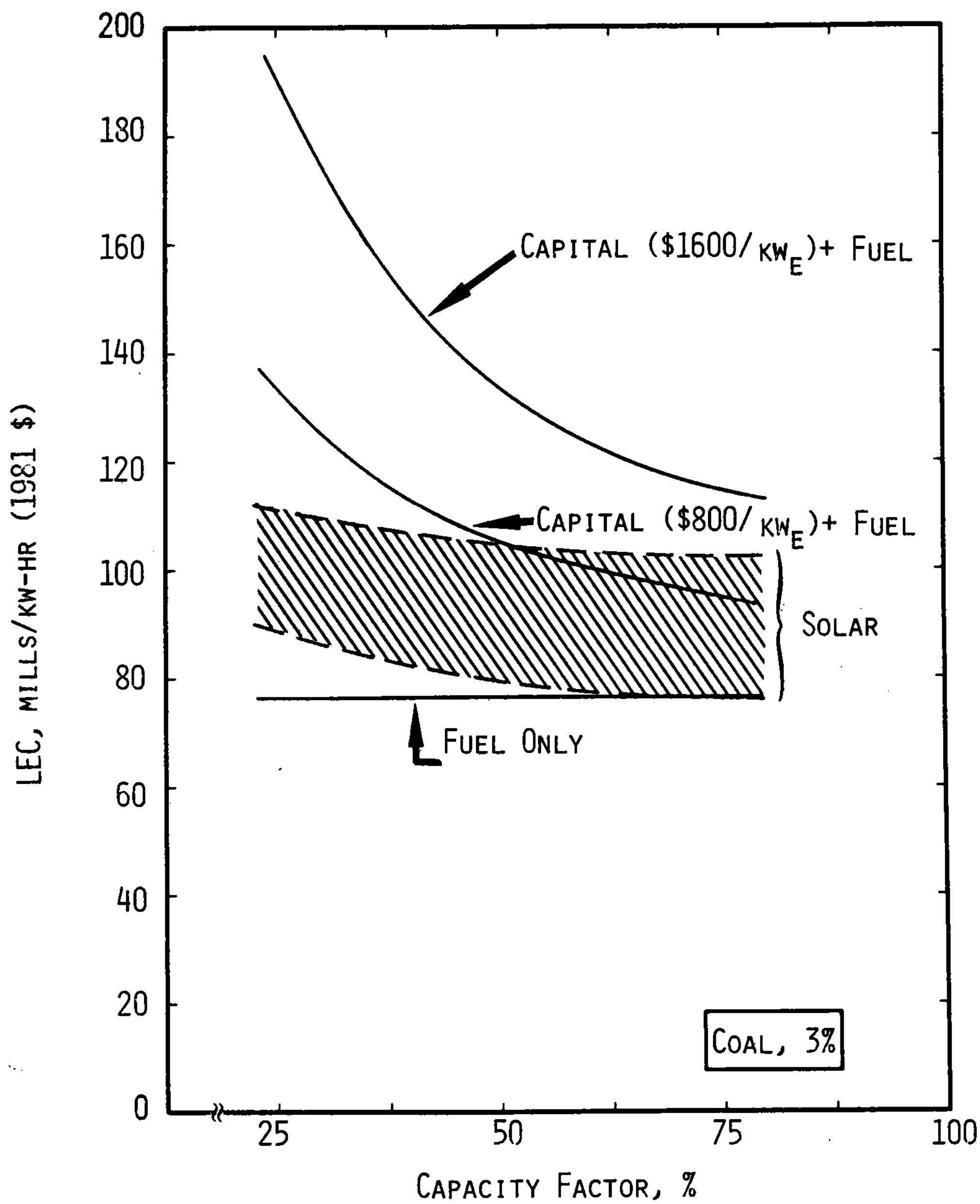

Figure 9. Energy cost comparison of central receivers and coal fired plants; 3% fuel escalation rate above inflation

1990 timeframe (ref. 21). The effect of capital cost is indicated in Figures 7 and 8. The comparison with coal is most likely at capacity factors > 50% - 60% where most coal plants are designed to operate. In this case, central receivers become competitive under a scenario somewhat stricter than for oil or natural gas, but still plausible, i.e., the concurrence of some capacity credit with high real fuel price escalation rates and/or high coal plant construction costs.

Industrial Process Heat (IPH) Generation

Capital Costs of Central Receiver Plants

The molten salt receiver/storage system has been shown to be the most economic technology choice for a wide range of delivered process steam temperatures in IPH applications (ref. 22). Therefore, the same baseline system as the electrical case less the turbine/generator subsystem has been used and redesigned to 300 MW_{th} for the IPH comparison in this report. In comparing solar plants with fossil options for IPH, the most straightforward, but strictest comparison is on the basis of fuel displacement alone. The justification for this type comparision arises from the fact that most industrial processes are continuous with high (>95%) reliability factors, so that any solar plant will probably be built with a conventional backup system for process energy supply. The value of the solar plant will then be based on the fuel it displaces and no "capacity credit" will be allowed as in the electrical case.

While fuel displacement is probably a good basis for comparing central receivers with existing oil and gas burning facilities, the more plausible comparison with coal should include consideration of capital requirements. As discussed in reference 7, few existing facilities are equipped to burn coal. Therefore, the required investment in coal handling and burning equipment should be added to the fuel costs for comparison to the capital and operating expenses of a central receiver plant. New plant comparisons should be similarly treated; i.e., a coal plant designed specifically for the application, including backup equipment and fuel expenses, should be compared to the appropriate central receiver plant meeting the same operating and reliability requirements. (The likely central receiver plant concept is a hybrid with the most cost effective fossil option.) Unfortunately, the current lack of information on coal plant costs for industrial applications (i.e., smaller scale applications compared to utilities) has restricted the comparison here to fuel displacement alone. A solar plant with buffer storage only designed for a Barstow, CA location is used. Under the same assumptions as the electrical case, a capital cost range for central receivers of \$245 - \$380/kW_{th} (\$30 - \$47/10^6 BTU/yr), results.

Economic Assumptions

The economic assumptions are based on information about industrial financing practices (ref. 7) and the relation between the general inflation rate and rates of return outlined earlier. Table V gives the values of the parameters used.

TABLE V

ECONOMIC ASSUMPTIONS FOR INDUSTRIAL PROCESS HEAT APPLICATIONS

Fixed charge rate (FCR)	22.9%	
% Equity financing		100.0%
Rate of return (after tax)		15.0%
Income tax rate		48.0%
Property tax, insurance		2.5%
Investment tax credit		10.0%
Tax life (sum-of-years digits)		16 yrs
Operating life		20 yrs
General inflation	8.0%	
Capital escalation	8.0%	
Plant start-up	1992	

Fossil Fired Plants

Table VI summarizes the assumptions on fossil fuels used in the IPH case. Since the comparison is based on fuel displacement only, capital costs of the fossil facilities do not enter into the caluclations. Note that the initial coal price is assumed somewhat higher than for the utility case. While few industries are currently burning coal, several have investigated the costs of retrofitting (ref. 7). Delivered coal prices are expected to be higher than

TABLE VI

FOSSIL FUEL ASSUMPTIONS FOR INDUSTRIAL PROCESS HEAT APPLICATIONS

	Oil	Gas	Coal
Fuel cost (1981 $\$/10^6$ BTU)	4.00	2.50	2.00
Fuel escalation above inflation (%/yr)	0→3	0→3	0→3
Boiler efficiency (%)	75	75	75

for the utilities. The smaller average industrial plant size and the accompanying decreased capability for coal storage and handling mean smaller unit buys and, thus, higher prices. The same range on fuel escalation rates as in the utility analysis is used. Appendix C gives a comparable scenario with variable escalation rates.

Levelized Energy Cost Comparisons for Industrial Process Heat

Figure 10 compares the levelized energy cost from a central receiver plant with buffer storage only vs. the levelized fuel cost of conventional options. As indicated, the range on solar costs covers the baseline estimates plus the same allowed variations on solar component costs as used for the utility comparison. The range on fuel costs reflects the range on fuel escalation rates analyzed.

Similar to the utility case, the most conservative assumptions, i.e., negligible fuel escalation above inflation plus higher solar costs show that central receivers will be competitive with oil simply because of its high current prices. Substantial overlap of the natural gas and solar bands indicates the likelihood of central receiver competitiveness with this fuel, as well. Finally, the higher coal price in industrial applications results in the central receiver comparing favorably under the plausible scenario of higher coal escalation rates coupled to the attainment of baseline solar system costs. The addition of a capital cost contribution to the coal fuel value band will lead to an even more favorable comparison of central receivers with the coal option.

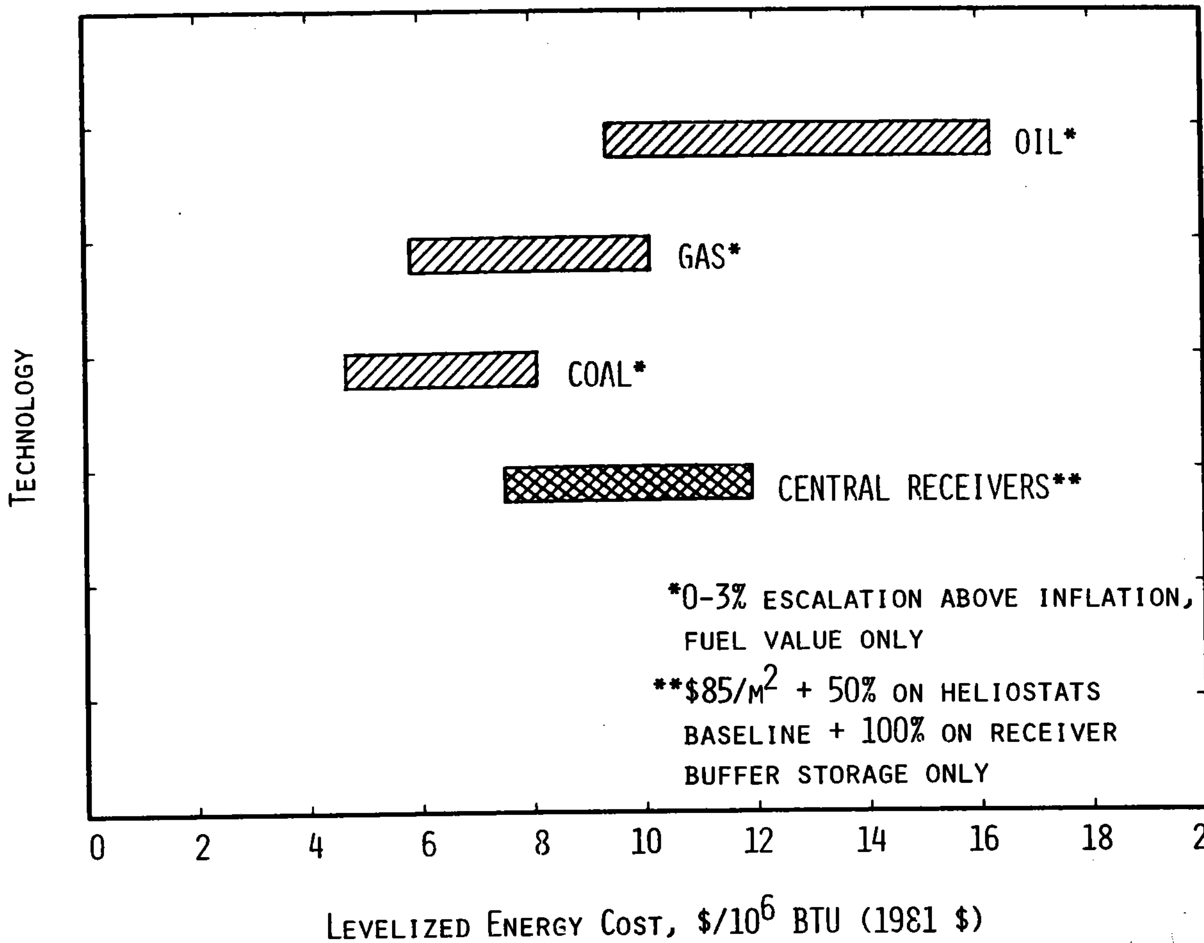

Figure 10. Energy Cost Comparison of Central Receivers and Fossil Fuels for Industiral Process Heat

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22. J. D. Fish, et al., "Central Receiver Steam Systems for Industrial Process Heat Applications," Sandia Laboratories, Livermore, SAND81-8223, April 1981.

APPENDIX A--CALCULATION OF THE FIXED CHARGE RATE

The fixed charge rate (FCR) is calculated according to the following relation:

$$FCR = PTI + \frac{(1.0\text{-}ITC) - (ITR \times DEP)}{(1.0\text{-}ITR)\ f_{DIS}} \qquad \text{(A-1)}$$

where PTI = annual property tax and insurance rate;

ITC = investment tax credit;

ITR = income tax rate;

DEP = depreciation allowance (see equation A-2);

f_{DIS} = discount factor (see equation A-4).

The depreciation allowance will depend on the depreciation schedule used. The sum-of-years digits schedule gives:

$$DEP = \sum_{y=1}^{Y_{DEP}} \frac{2(Y_{DEP} - y + 1)}{Y_{DEP}\ (Y_{DEP} + 1)\ (1 + r_{DIS})^{y}} \qquad \text{(A-2)}$$

where Y_{DEP} = depreciation life of the plant;

r_{DIS} = discount rate.

The discount rate is the effective cost of money to the plant owner and includes both debt costs and return on equity requirements according to:

$$r_{DIS} = [(1.0 - ITR)\ f_D + f_{PS}]\ i_D + f_{cs}\ i_{ROR} \qquad \text{(A-3)}$$

where f_D = debt fraction;

i_D = debt cost;

f_{PS} = fraction preferred stock;

f_{CS} = fraction comon stock;

i_{ROR} = rate of return (before - tax).

The discount factor is calculated from the discount rate:

$$f_{DIS} = \sum_{Y=1}^{Y_{OP}} \frac{1.0}{(1.0 + r_{DIS})^y}$$

where Y_{OP} operating life of the plant.

APPENDIX B--RESULTS FOR A SCENARIO ASSUMING A HIGHER INFLATION RATE

Results for a different economic scenario in which the underlying inflation rate is assumed higher than in the main text are presented in this section. The relative ratios of the debt cost and rate of return to the inflation rate are kept the same as in the scenario of the main text. Table B-I gives the economic assumptions for the utility case. Figure B-1 is a plot of the levelized energy costs of central receivers based on the capital costs of Figure 1 in the main text and the economic parameters of Table B-I. Figures B-2 to B-7 are the corresponding comparisons with oil, gas, and coal fired plants at the lower and upper limits of the fuel escalation rate used throughout the analysis.

The economic assumptions for the industrial process heat case are found in Table B-II. The levelized energy cost comparison of central receivers with fossil fuels is presented in Figure B-8.

Qualitatively the conclusions of the main text still hold for this scenario; namely, central receivers can be cost-competitive with oil under the most conservative assumptions and with gas under assumptions of modest fuel escalation rates and allowed capacity credit (utility cases) coupled to attainment of the lower range of central receiver costs considered. Competitiveness with coal is also assured if high real fuel price escalations and/or high plant construction costs occur with some allowed capacity credit for central receivers. Quantitatively, the results emphasize the significant increases in energy costs (25-50%) which will accompany a sustained high inflation rate regardless of the energy source.

TABLE B-I

ECONOMIC ASSUMPTIONS FOR INVESTOR OWNED UTILITIES
HIGH INFLATION RATE SCENARIO

Fixed charge rate (FCR)	20.5%	
Discount rate		13.1%
Income tax rate		48.0%
Property tax, insurance		2.5%
Investment tax credit		10.0%
Tax life (sum-of-years digits)		24 yrs
Operating life		30 yrs
General inflation	12.0%	
Capital escalation	12.0%	
Plant start-up	1992	

* Debt fraction = 0.5
Debt cost = 15.0%
Fraction preferred stock = 0.1
Fraction common stock = 0.4
Rate of return (before tax) = 19.25%

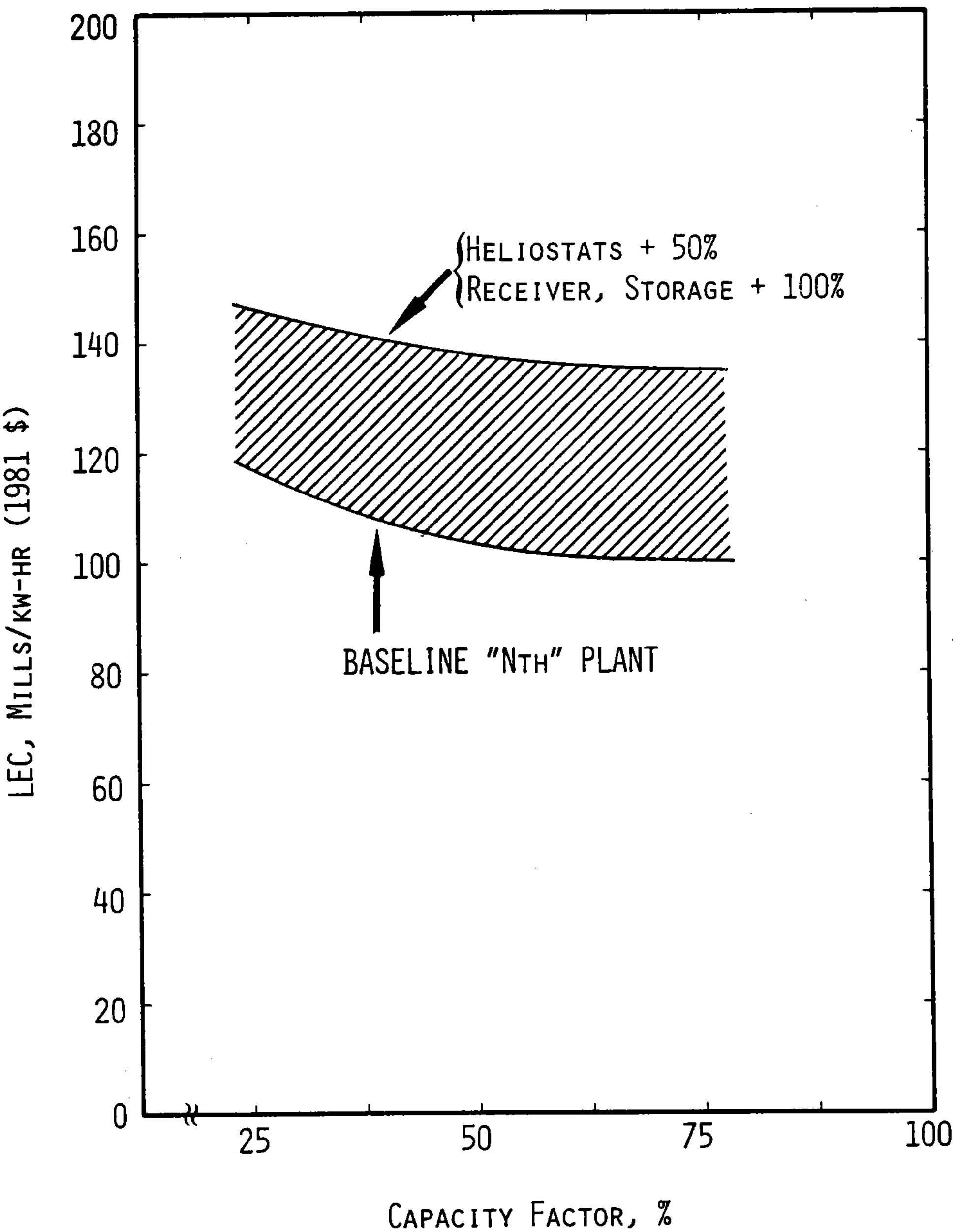

Figure B-1. Levelized Energy Cost of Central Receivers vs. Capacity Factor; 12% Inflation Rate

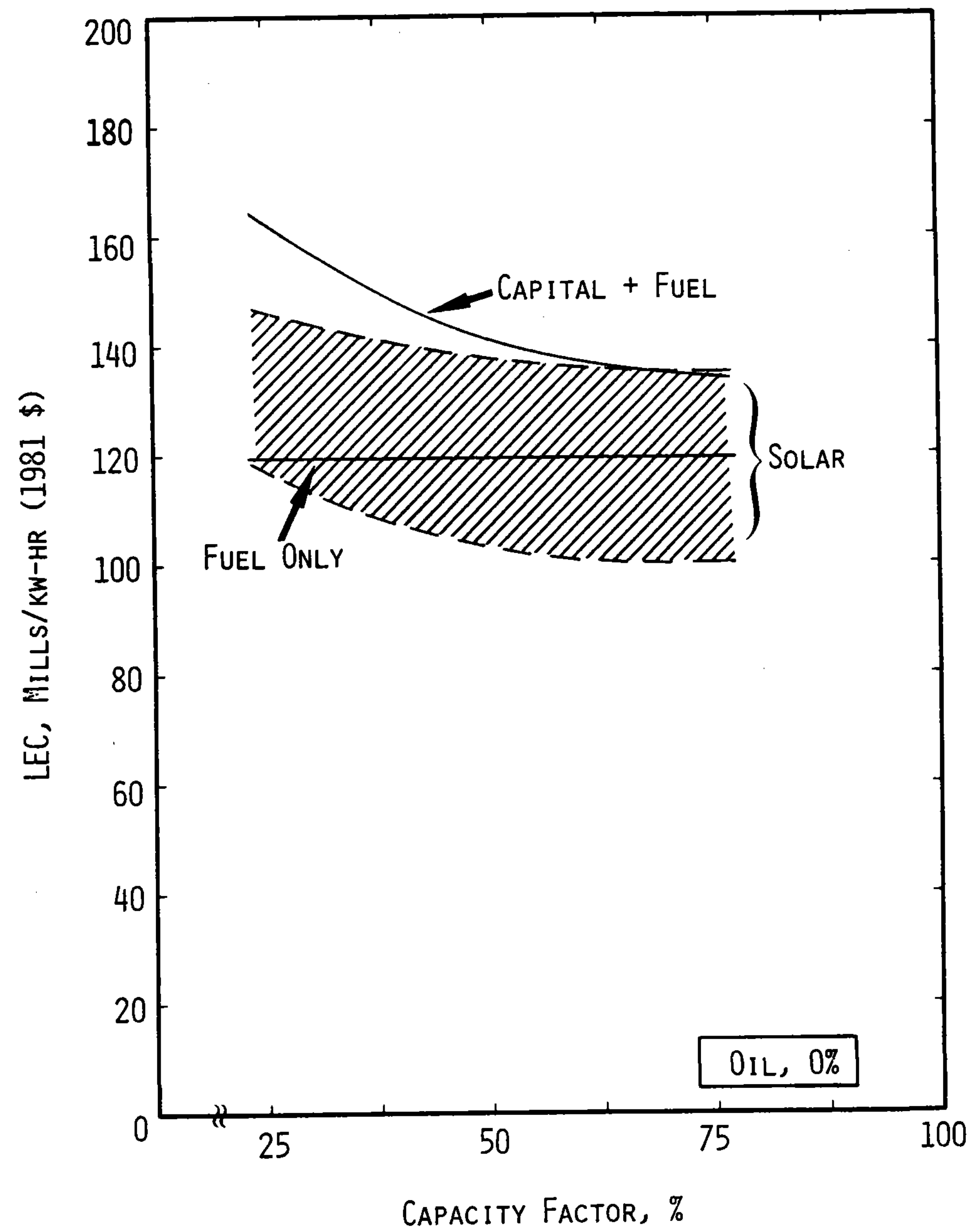

Figure B-2. Energy Cost Comparison of Central Receivers and Oil Fired Plants; 12% Inflation, 0% Fuel Escalation Rate above Inflation

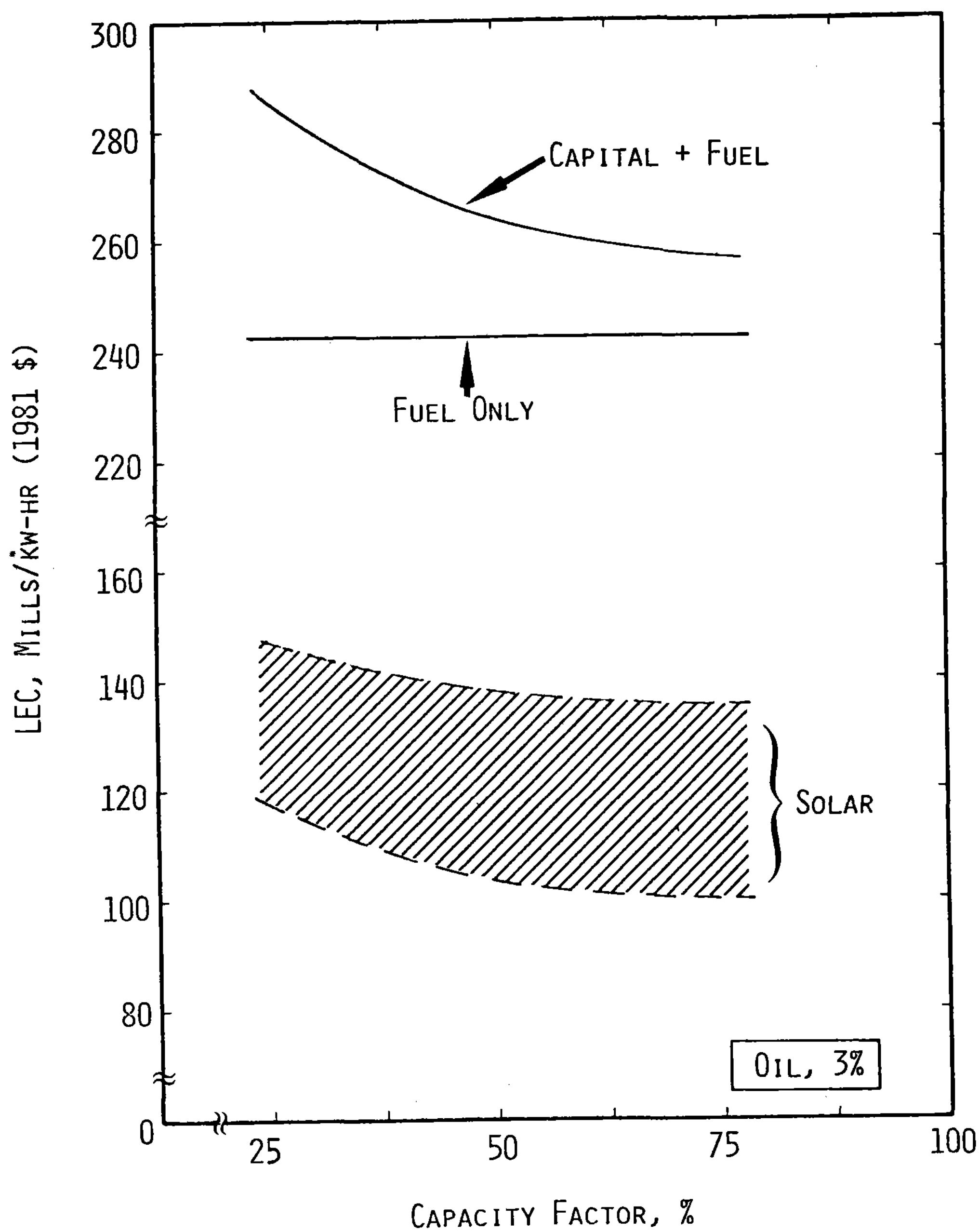

Figure B-3. Energy Cost Comparison of Central Receivers and Oil Fired Plants; 12% Inflation, 3% Fuel Escalation Rate above Inflation

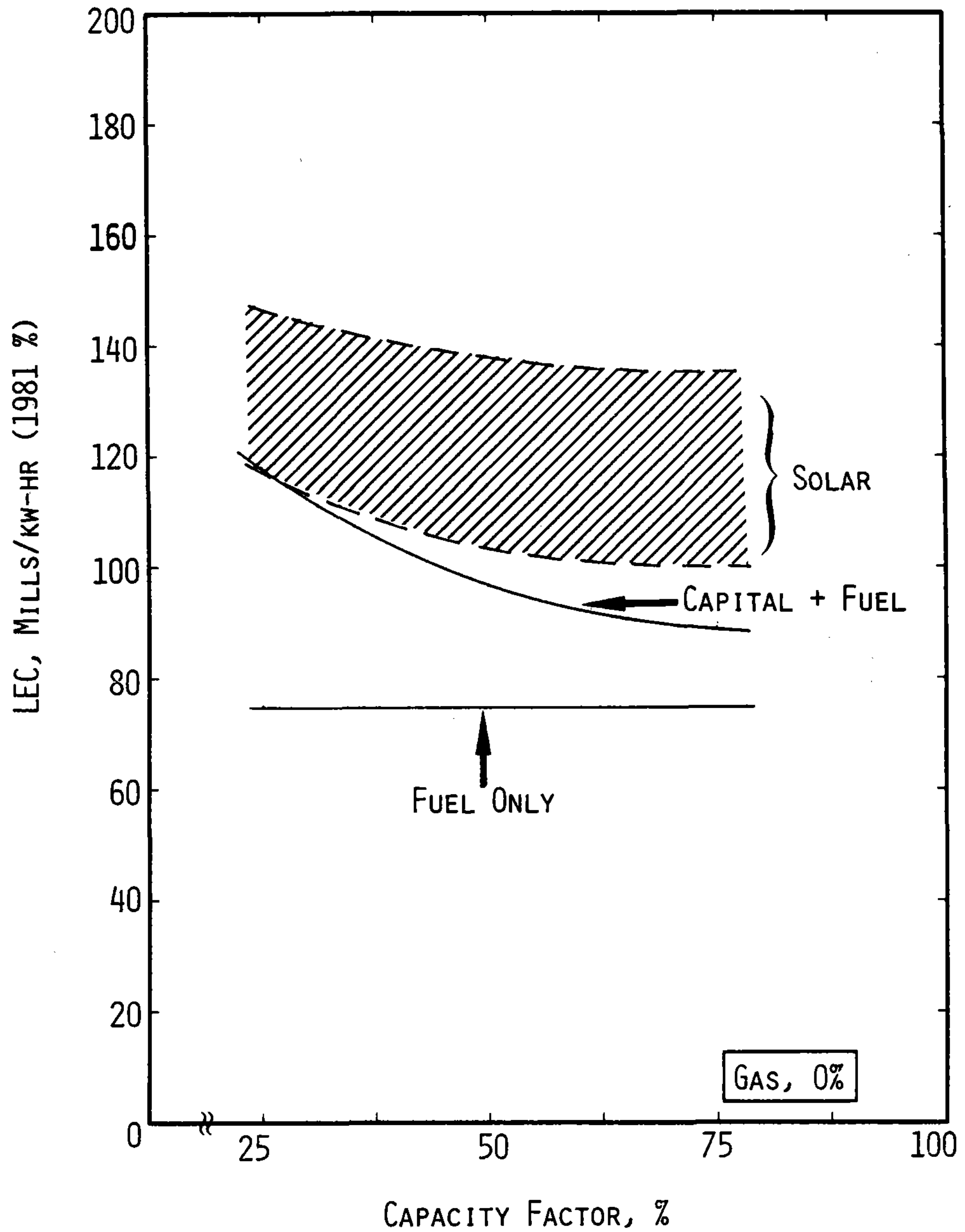

Figure B-4. Energy Cost Comparison of Central Receivers and Gas Fired Plants; 12% Inflation, 0% Fuel Escalation Rate above Inflation

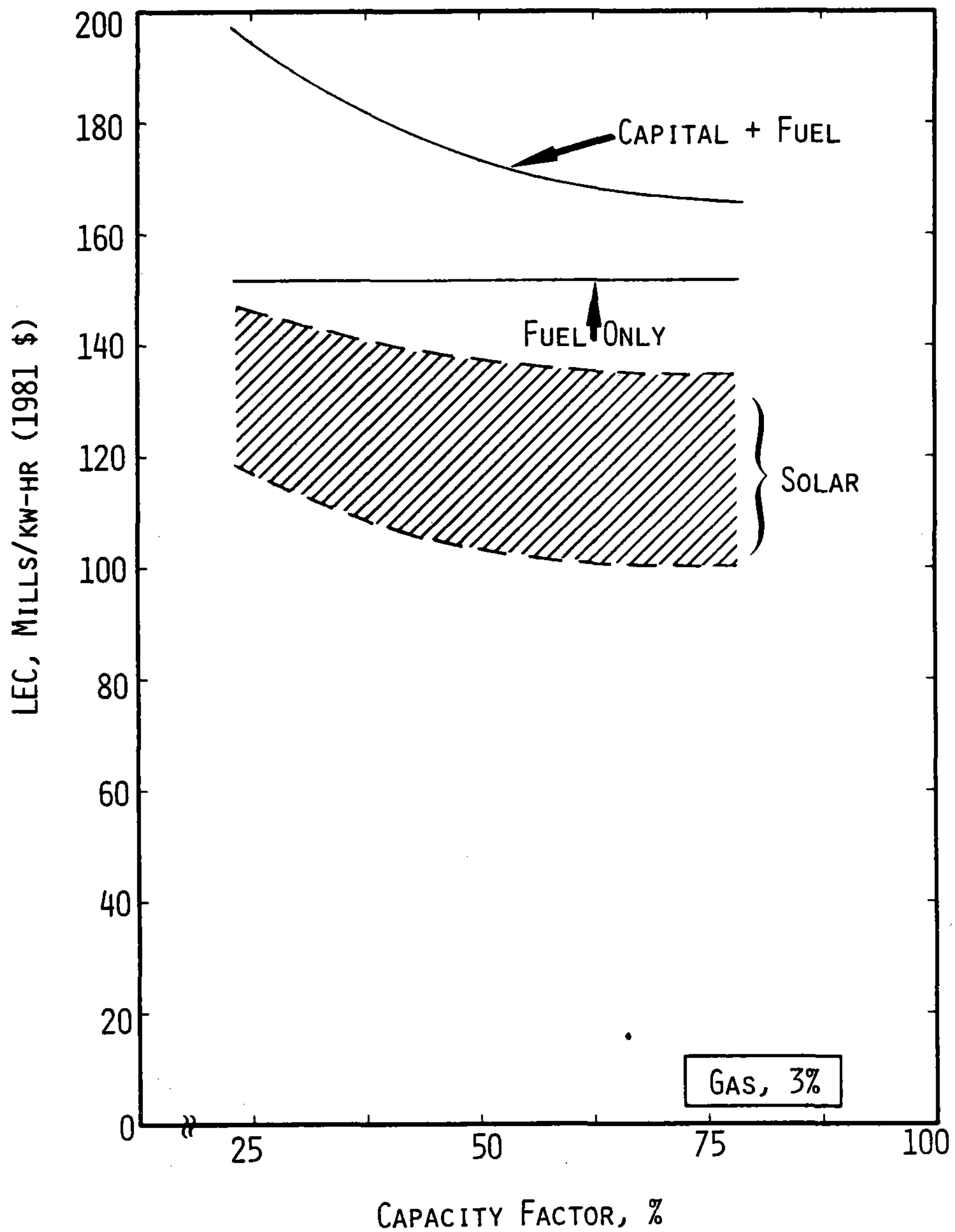

Figure B-5. Energy Cost Comparison of Central Receivers and Gas Fired Plants; 12% Inflation, 3% Fuel Escalation Rate above Inflation

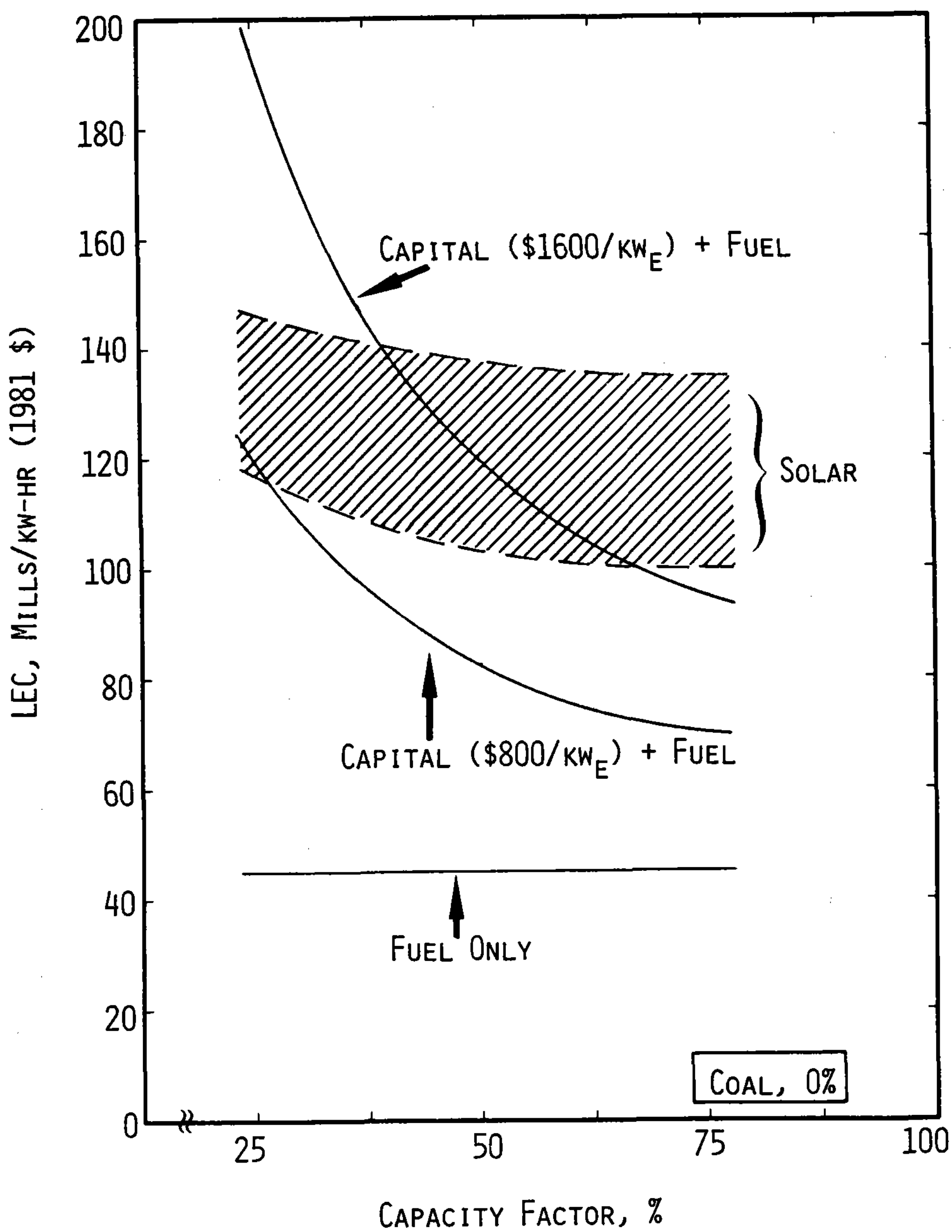

Figure B-6. Energy Cost Comparison of Central Receivers and Coal Fired Plants; 12% Inflation, 0% Fuel Escalation Rate above Inflation

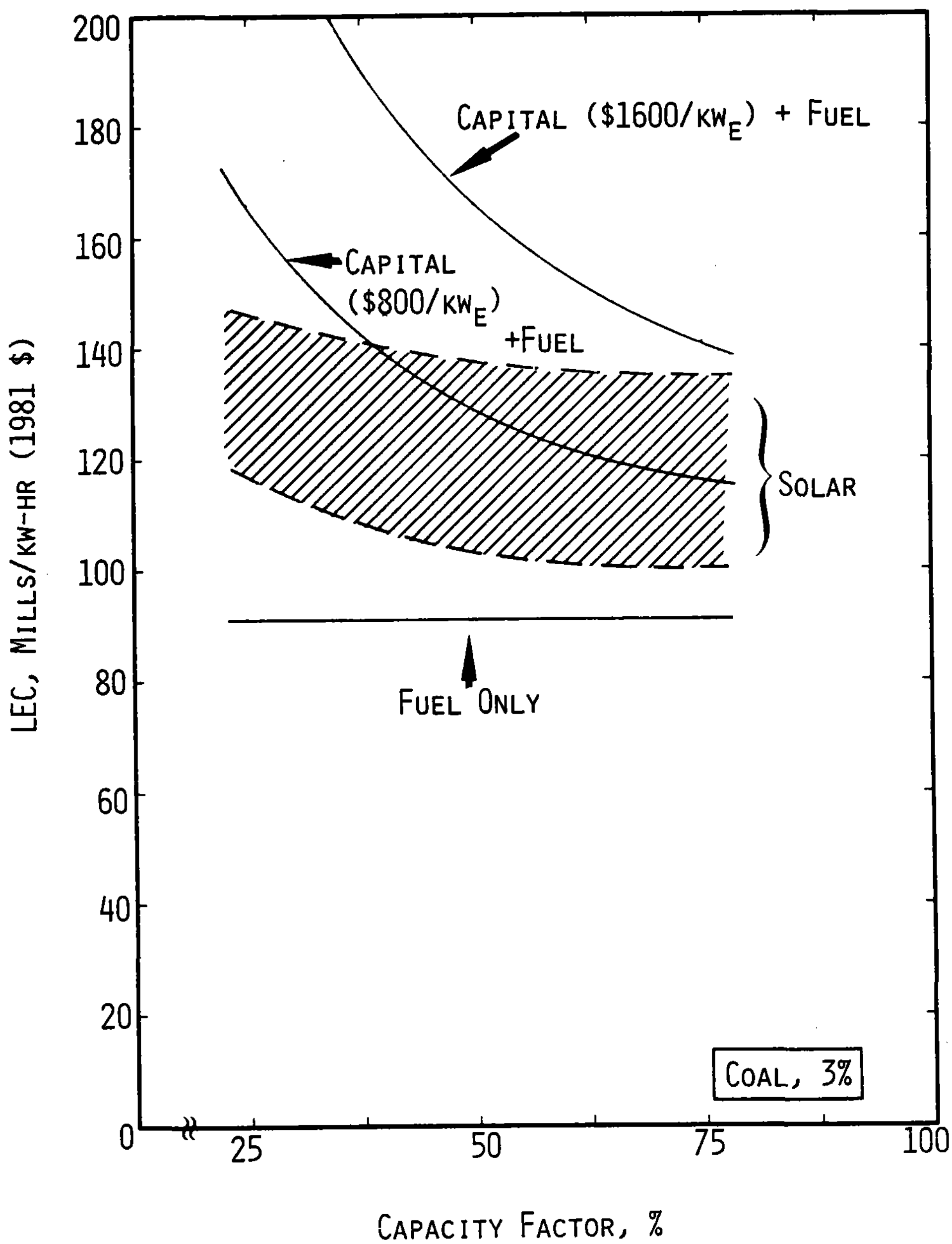

Figure B-7. Energy Cost Comparison of Central Receivers and Coal Fired Plants; 12% Inflation, 3% Fuel Escalation Rate above Inflation

TABLE B-II

ECONOMIC ASSUMPTIONS FOR INDUSTRIAL PROCESS HEAT APPLICATIONS
HIGH INFLATION RATE SCENARIO

Fixed charge rate (FCR)	29.1%	
% Equity financing		100.0%
Rate of return (after tax)		19.25%
Income tax rate		48.0%
Property tax, insurance		2.5%
Investment tax credit		10.0%
Tax life (sum-of-years digits)		16 yrs
Operating life		20 yrs
General inflation	12.0%	
Capital escalation	12.0%	
Plant start-up	1992	

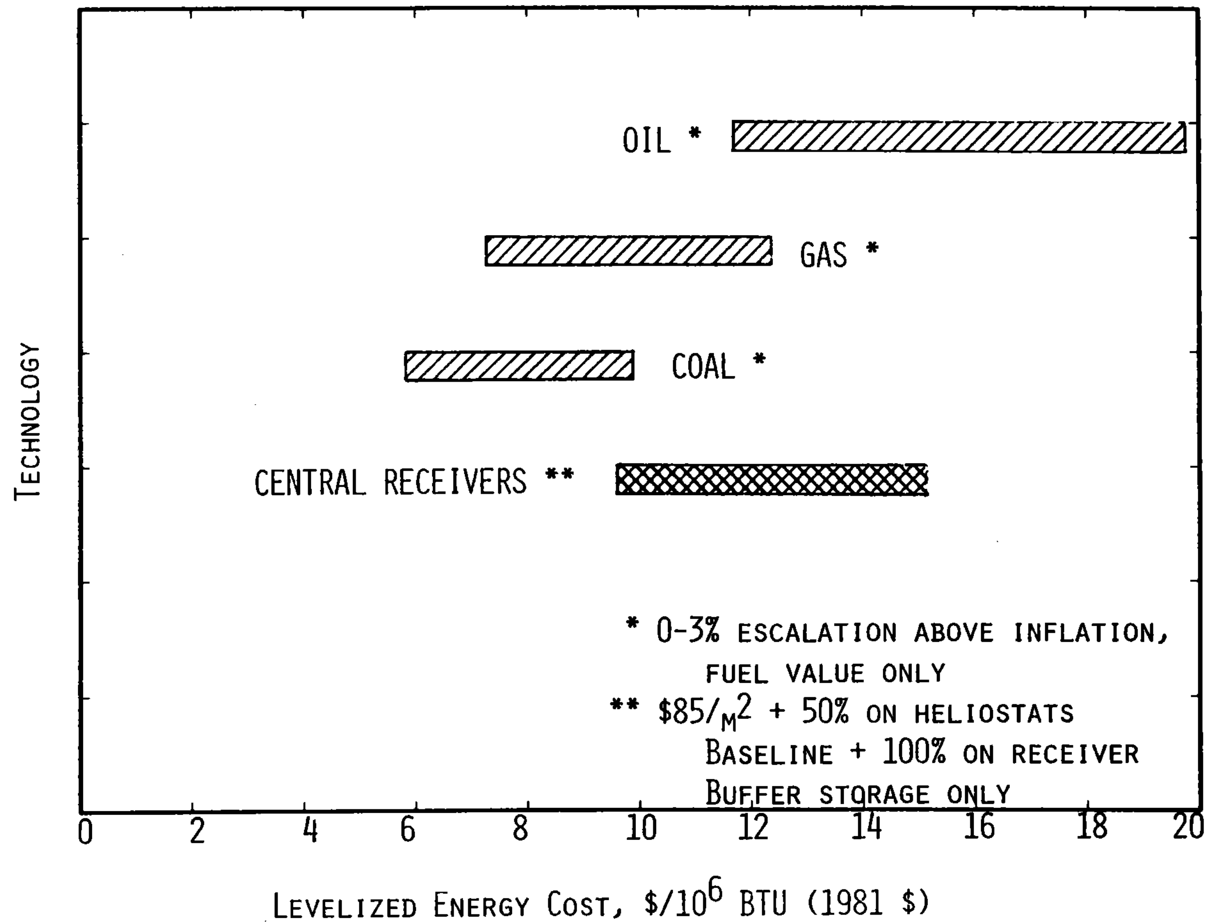

Figure B-8. Energy Cost Comparison of Central Receivers and Fossil Fuels for Industrial Process Heat; 12% Inflation Rate

APPENDIX C--EQUIVALENT SCENARIOS OF CONSTANT AND VARIABLE FUEL ESCALATION RATE

Continued real escalation of fuel costs above inflation throughout the 20 or 30 year life of a plant coming on line in 1992 seems unlikely. However, a variable escalation scheme equivalent to the constant scheme used in this report can be derived. High real fuel escalation rates (> 3%) are thought to be likely through the next decade with a gradual decline to meet general inflation in the 1990's. Two such schemes are presented in Figures C-1 and C-2 for electric utility and industrial applications, respectively, for the purpose of illustrating scenarios equivalent to the upper bound of 3% above inflation considered here. The 20 year life assumed for industrial applications compared to a 30 year economic life for utility plants leads to a correspondingly shorter period of real fuel escalation rates required for a variable scheme scenario following the same initial trend as used here. (Equivalently, lower real fuel escalation rates for industrial plants over the same period of time as a utility analysis would provide a second way of comparing the two markets.)

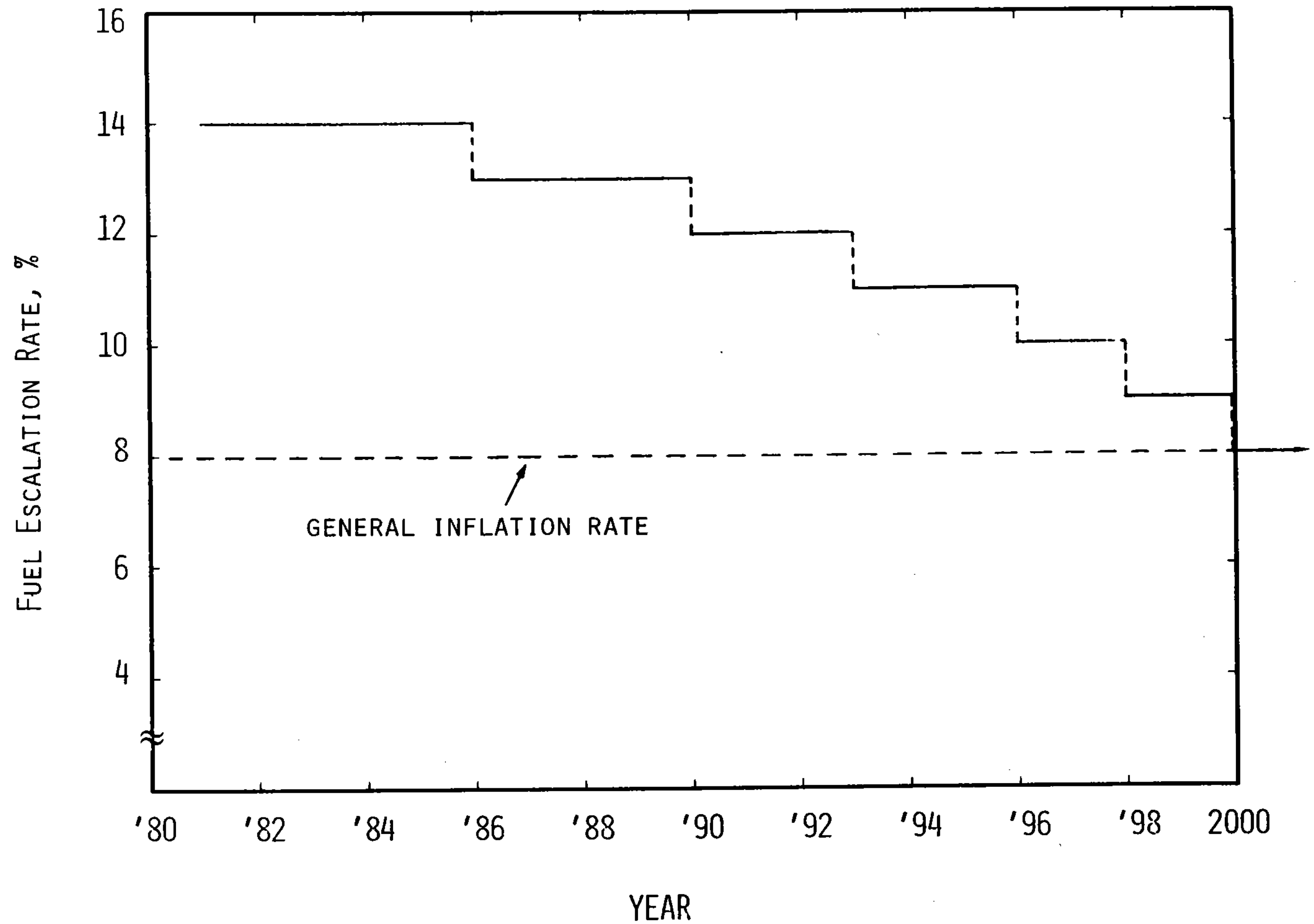

Figure C-1. Variable Fuel Escalation Rate Scenario Equivalent to a Constant Rate of 3% above Inflation - Utility Application

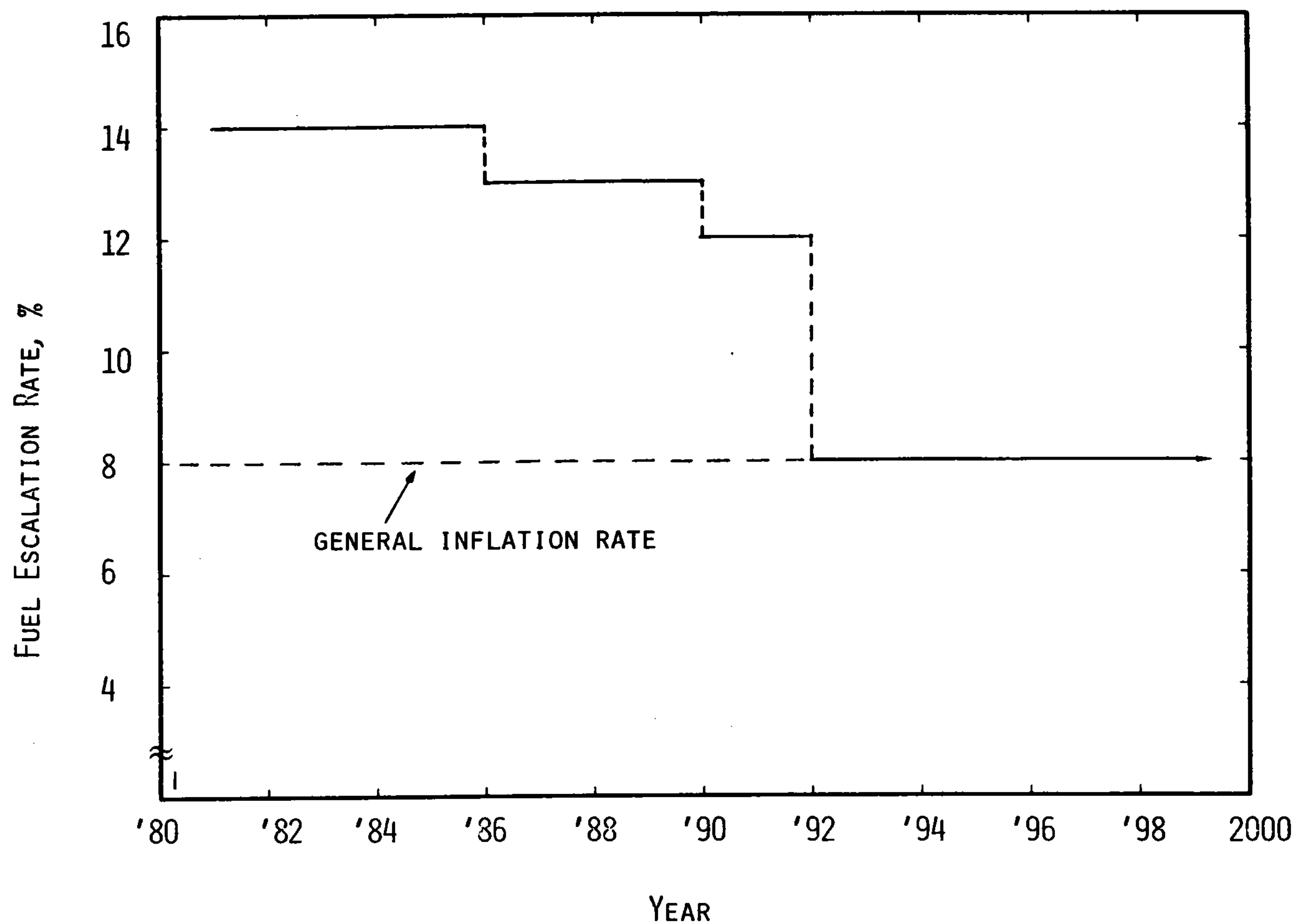

Figure C-2. Variable Fuel Escalation Rate Scenario Equivalent to a Constant Rate of 3% above Inflation - Industrial Process Heat Application

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