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Point-Focusing
Thermal and Electric Applications Project

Electric Energy Costs of Southwestern U. S. Utilities to the Year 2000

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

ABSTRACT

To analyze the economic feasibility of small solar thermal electric power systems, it is important to determine the cost of electrical generation by conventional sources in the 1985-2000 period. To obtain planning information relating to the generation of electric power, nine electric utilities located in high insolation areas of California, Arizona, New Mexico and Texas were surveyed and visited. Information was obtained on present capabilities, plans for future generation and transmission, environmental constraints, present and anticipated water availability, reserve requirements, costs, and reliability. These utilities plan to double their installed generating capacity by 1995. However, the types of new energy sources vary with specific utilities. For example, in Arizona and New Mexico the utilities will rely on new mine-mouth coal plants located in northern Arizona and New Mexico, and on a massive 5-unit 6500 MW nuclear plant near Phoenix. Transmission lines of 200 to 600 miles in length will transmit the power to the load centers. On the other hand, three California utilities plan to double their generation resources by relying on oil and geothermal sources. They also expreseed interest in sharing ownership in large coal or nuclear plants if and when they are built in the Southwestern United States. Transmission lines for Southern California utilities are generally less than 100 miles long.

In the Southwest U.S., the energy cost from these additions to the present systems will depend upon numerous factors. Estimates of electric power costs were determined for a variety of scenarios including investor-owned and municipal utility operation; startup dates of 1986, 1995 and 2000; range of fuel prices; various fossil and nuclear technologies; time delays in constructing plants; plant capacity factors of 0.3 and 0.6; and fuel escalation rates of 1% and 2% above a 6% inflation rate. Energy costs in the 1985-2000 period were computed as a function of fuel prices. Using five independent fuel price forecasts, the energy costs range from 50 to 100 mills/kWh for baseload plants and 70 to 200 mills/kWh for intermediate load plants (1978$).

In addition to costs, other factors need to be considered in determining the rate at which small power systems can be expected to be adopted on a broad scale. For example, institutional factors control the rate at which new coal fields, fuel transport systems, and electric power plants can be constructed.

Detailed profiles of the present and future electric generation plans for the nine utilities were developed. The study included a summary of electricity generation of the southwest utility, an overview of present and future alternative fuel availability to utilities, and a description of the methodology used for computing levelized busbar energy costs.

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SECTION I

INTRODUCTION

A. BACKGROUND

The Small Power Systems Applications Project (now known as Point-Focusing Thermal and Electric Applications (PFTEA) Project) was initiated to determine the technical, economic and institutional feasibility of providing small communities, remote load centers, rural areas, and industrial users with an energy source based on solar thermal conversion. Small Power Systems of 10 MWe or less can be located close to, or coupled with, load centers. A number of solar thermal technologies can be employed to meet the specific requirements of a particular application, including point and line focusing distributed receiver, and small central receiver systems, which may incorporate Rankine, Brayton, or Stirling engine power conversion subsystems.

The overall goal of the PFTEA Project is to establish technical, operational, and economic readiness of small solar thermal power sytems. The project will develop systems to the point at which subsequent commercialization activities can proceed and lead to successful market penetration. Applications that currently derive power from high cost energy sources seem to be the first feasible markets. Initial commercial adoption for higher cost energy markets is targeted for the mid-1980's with widespread adoption to occur in the post-1990 time frame.

To assist this technology development effort, researchers at the Jet Propulsion Laboratory have begun to investigate the requirements of prospective users of solar thermal electric systems. This study concerns economic requirements of the utility industry during the last two decades of the 20th Century. Subsequent studies will address requirements of other potential user groups.

B. STATEMENT OF PROBLEM

The utilities represent a potentially large market for Small Power Systems. However, the utilities may utilize several types of power plants, including conventional designs for fossil-fired and nuclear LWR (light water reactor) systems and combustion turbine peaking plants. By the end of the century, the utilities will have choices of advanced technologies such as fluidized bed combustion, geothermal, wind, large solar thermal central receiver, photovoltaics and others. The problems for the cost goals study can be framed as follows:

(1) What competition can small power systems be expected to face for electric utility applications in the 1985-2000 period?

(2) What economic goals should the PFTEA Project achieve in order to be able to compete successfully against new plants based on conventional technologies in this environment?

SECTION II

ENERGY COST ANALYSIS

A. PROJECT GOALS

The cost of power from new power plants is expected to rise rapidly over the next decade. Determining a reasonable, realistic scenario for energy costs requires consideration of numerous factors. This study is an attempt to develop a consistent set of such cost scenarios.

The range of expected energy costs, based on information available in the first half of 1978, is shown in Figure 2-1. The range varies from 50 mills/kWh for baseload plants to 200 mills/kWh for combustion turbines in intermediate load service in 1978 dollars.

Finding the basis for the likely cost of energy from new power plants is the subject of the following sections.

B. ENERGY COSTS

The approach taken for the study included the following:

(1) Identify utilities in the Southwest U.S. that might utilize small power systems during 1985-2000 and beyond. Analyze their publications; e.g., annual reports, bond prospectuses, future generation plans to obtain costs of conventional power plant systems coming on-line during the 1980's.

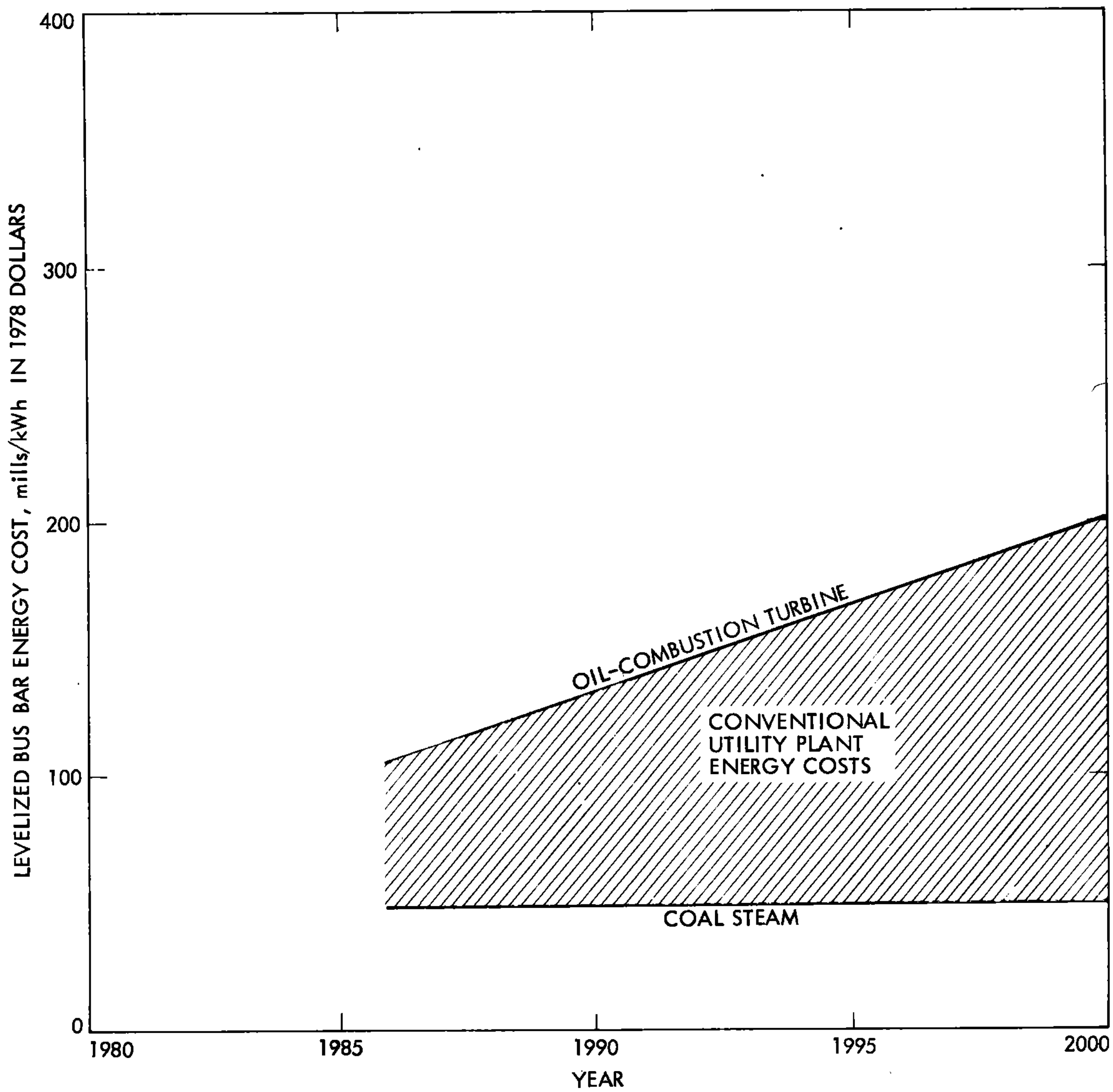
(2) Interview utility plannners to obtain their perspectives on solar electric applications as well as their outlook for conventional power generation technology, growth, and expected costs. Compare with the literature on future energy supply and energy cost.

(3) Create realistic scenarios for expected load growth, escalation of prices, power plant technologies, fuel costs, and other economic factors.

(4) Compute levelized busbar energy costs for various conventional technologies, escalation rates, and fuel prices.

(5) Compute a range of conventional utility energy costs for new plants based on fuel price forecasts, cost of new power plants, heat rates and a consistent set of inflation, and escalation assumptions.

The first utility market for solar thermal electric systems in the U.S. consists of firms in the southwest, an area of high insolation. Because of a number of factors such as available capital, present equipment, service area, management philosophy, regional history, and



NOTE: Costs shown are for new plants coming on-line in year indicated. All proposed utility technologies will have costs lying within the range shown.

Figure 2-1. Energy Costs For Southwestern U. S. Utilities in the Years 1986-2000 local governmental requirements, each utility has a different perspective of the means to meet future demands.

In the following analysis, average busbar energy costs were compared for various technologies, fuel costs and escalation rates for units coming on line in 1986, 1995, and 2000. A capacity factor of 0.6 was used for baseload units and 0.3 was used for intermediate to peaking duty units.

The inflation assumption throughout the period 1978-2000 is 6%. Prices of fuel, capital equipment and labor, operations and maintenance costs escalate at 1% above inflation for most of the cases. In a few cases, higher escalations were assumed.

Capital costs, transmission costs and tax rates selected are typical of an investor-owned southwestern utility. They are based on data from utility annual reports and financial prospectuses (Refs. 44-55).

The basis for conventional plant capital costs is the costs of actual plants to which the utilities are committed. Two of these power plants are located in multiplant complexes so that common site costs are shared over several units. Both plants are located in the Southwest at distances up to six hundred miles from their load centers. While much of this transmission network is already in place, additional carrying capacity needs to be built. The plants incorporate the latest engineering practice and meet local regulatory standards. Furthermore they will begin their operations in the early to mid 1980's. In this way the capital costs, transmission facilities, regulations, locations, and time of first operation would be similar to those against which the first generation of small solar thermal electric plants might be expected to compete.

The capital costs used for power plants are based on actual nuclear and coal plants now under construction in the U.S. Southwest. For example, at Palo Verde No. 3, a 1270 MW light water reactor is scheduled to come on line in 1986. It will be located west of Phoenix near Wintersburg. The electric power plant is owned by six utilities (Public Service of New Mexico, El Paso Electric Co., Arizona Public Service, Salt River Project, Los Angeles Department of Water and Power, and Southern California Edison Company)[52]. San Juan No. 4, a 466 MW mine-mouth coal steam plant, scheduled to come on-line in 1981, is located in the Four Corners of New Mexico. It is owned by Public Service on New Mexico and Tucson Gas and Electric Company. The cost of these plants is estimated as follows[54]:

	PV No. 3	SJ No. 4
Capital Cost of Plant	752 ($/kW)	791 ($/kW)
Transmission Added to System	158	45
Interest During Construction	226	134
TOTAL (Current dollars)	1136	970
Conversion to 1978$	710	816

These actual costs are used in the analysis as typical costs of new coal steam and nuclear plants to be built in the Southwest during the next twenty years.

It is difficult to ascribe an accurate capital cost of transmission to a new power plant. Normally, the utilities add to their transmission network in a fashion to increase reliability of service for their expected loads from all generation sources. However, in order to compare capital cost of transmission with new sources coming onto line at the same time, the authors have computed the ratio of transmission cost per kilowatt. This value ranged from \$45 to \$272/kW for the utilities studied, and in the analysis an average value of \$100/kW was included in the capital cost of all other plant technologies used in the study. Utility planners acknowledged that such a figure was acceptable for the amount of transmission the utilities expected to build in the Southwest at this time, even though exceptions could be found.

Cost factors were needed for new types of power plants currently under advanced development, which will reach commercial availability before the end of the century. The costs of geothermal brine systems, magnetohydrodynamic generation (MHD), fluidized bed combustors, liquid metal fast breeder reactors (LMFBR) and advanced combined cycle systems are based on engineering estimates of what these new power plants will cost when they become ready for utility installation.[24]

The rest of the section is devoted to the development of energy cost analysis. Energy costs are computed and levelized busbar energy costs in mills/kWh are stated in 1978 dollars. Table 2-1 summarizes the capital cost assumptions for the computations.

The next set of figures show the levelized busbar energy costs as a function of fuel price. The technologies for baseload plants have been displayed in separate figures from the intermediate load plants. A figure for each of the years 1986 and 1995 and 2000 is shown so that a comparison may be made of energy costs for new power plants starting that year. One can enter each figure with a fuel price and read off the energy cost for each of the technologies. This technique was used in preparing Figure 2-1, where points from each of these figures corresponding to the high and low fuel prices forecasts were brought together in one display.

Figure 2-2 considers escalation of fuel prices, capital cost, maintenance and operations for the life of the plant as 1% above inflation. In Figure 2-3, the conditions are similar except escalation is calculated to be 2% above the inflation rate. Figure 2-4 considers the case for the baseload plants, originally scheduled for 1986 coming on-line in 1991, after a 5-year construction delay. Additional interest and construction escalation costs affect the energy cost.

Figure 2-5 shows the cost of power from intermediate load plants commencing operations in 1986.

Figure 2-6 and 2-7 show energy costs for baseload plants commencing operation in 1995 and 2000. A comparison of these baseload plants is

PLANT COST ASSUMPTIONS (1978 DOLLARS)								
TECHNOLOGY	HEAT RATE (Btu/kW hr)	CONSTRUCTION TIME (YEARS)	1986 YEAR OF COMMERCIAL OPERATION		1995 YEAR OF COMMERCIAL OPERATION		2000 YEAR OF COMMERCIAL OPERATION	
			$/kW[1]	$/kW/yr[2]	$/kW[1]	$/kW/yr[2]	$/kW[1]	$/kW/yr[2]
			CAPITAL COST	OPERATIONS COST	CAPITAL COST	OPERATIONS COST	CAPITAL COST	OPERATIONS COST
COAL	10,000	9	$ 816	12.2	$ 888	13.3	$ 931	14.0
COMBINED-CYCLE OIL	7,000	4	317	4.8	344	5.2	361	5.4
FBC	9,500	4	737	11.1	802	12.0	841	12.6
GAS TURBINE	14,000	4	227	3.4	247	3.7	259	3.9
GEOTHERMAL	29,000	4	721	10.8	785	11.8	823	12.3
LMFBR[3]	9,000	6			1251	18.8	1311	19.7
MHD[3]	7,400	7			880	13.2	922	13.8
NUCLEAR-LWR	10,000	11	710	10.7	773	11.6	809	12.1

NOTES

1. Value of capital expenditures plus interest during construction; based on 200 MW capacity of most efficient plant size for each technology. Also, all plants except gas turbine, combined cycle, and geothermal include the capital cost of transmission. Costs of coal, combined cycle, turbines and LWR plants based on utility survey; others come from Ref. 24.

2. Taken as 1.5% of capital cost, and equal to annual maintenance cost (fuel cost not included).

3. LMFBR and MHD will not be available options until 1995 or later.

Table 2-1. Plant Cost Assumptions

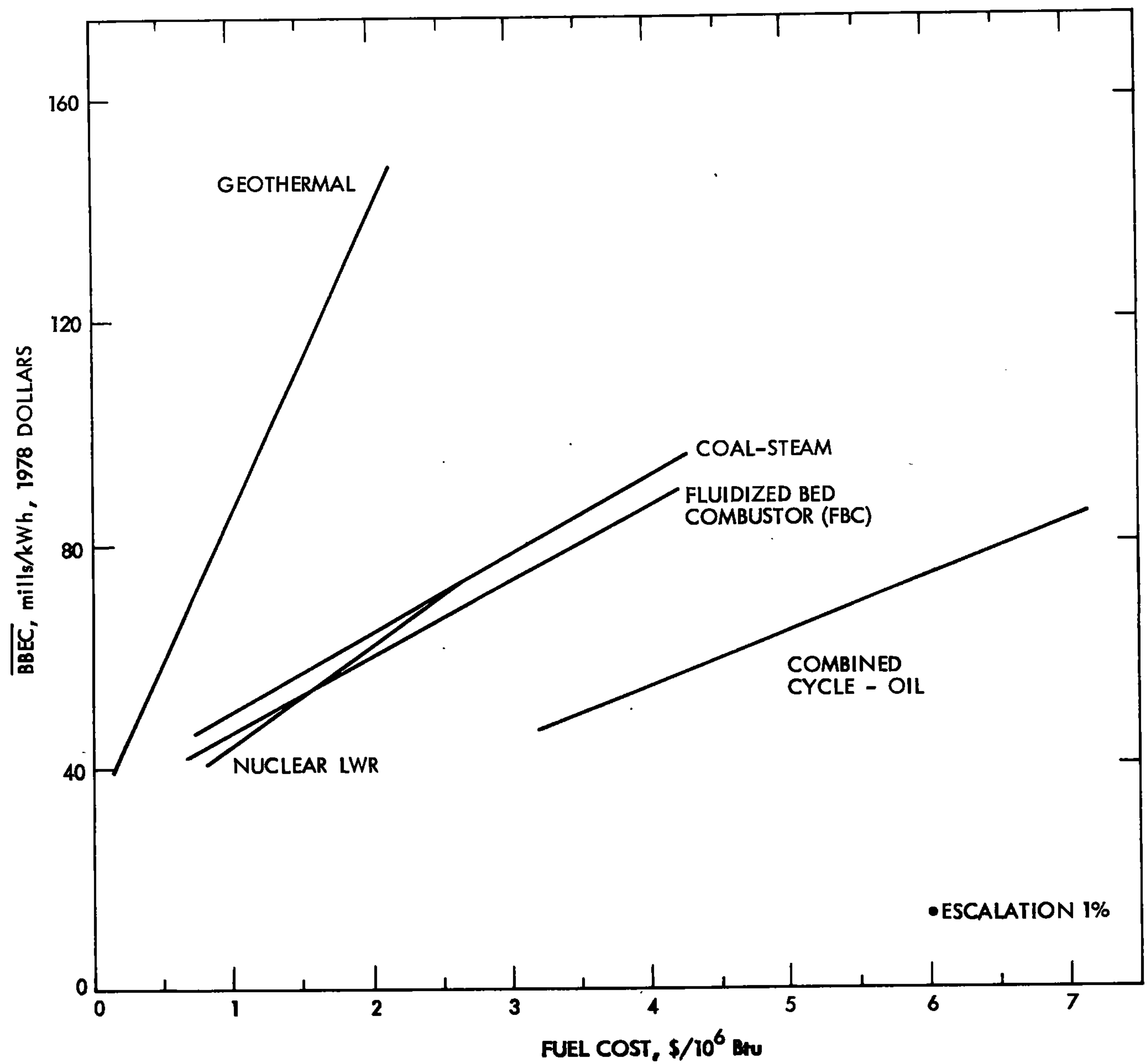


Figure 2-2. Levelized Bus Bar Energy Costs for New Baseload Plants Coming On-Line in 1986

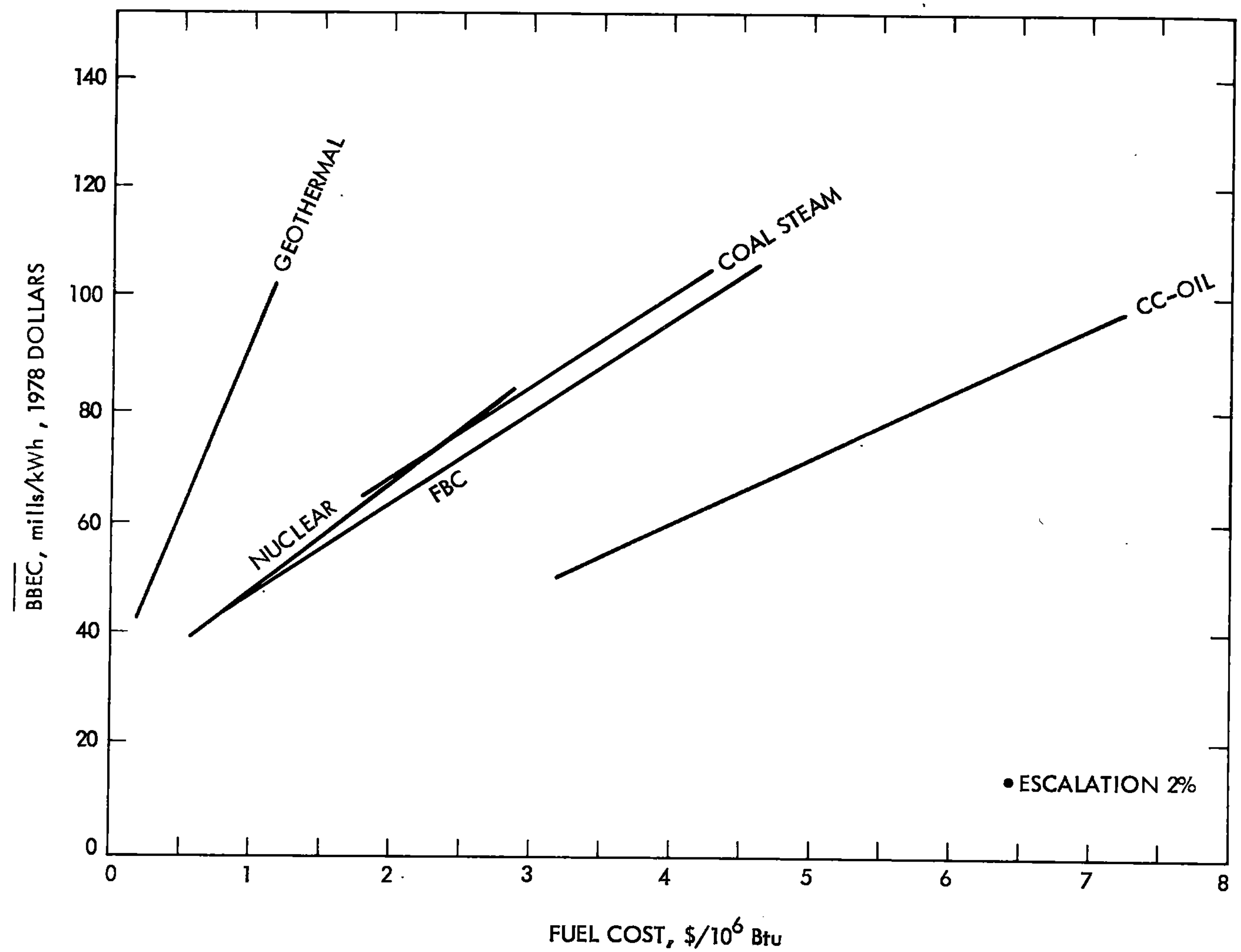


Figure 2-3. Levelized Bus Bar Energy Costs for New Baseload Plants Coming On-Line in the Year 1986

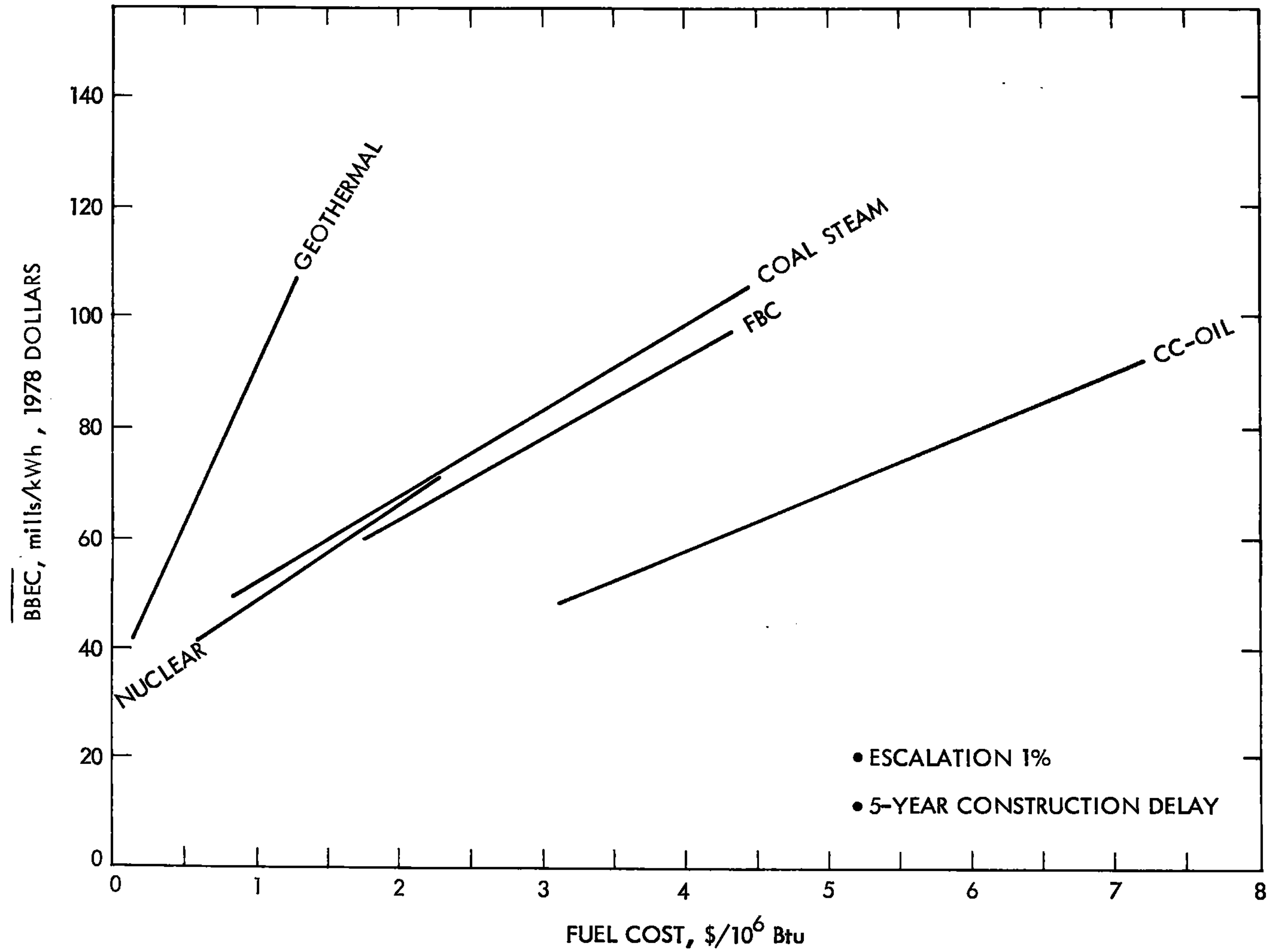


Figure 2-4. Levelized Bus Bar Energy Costs for New Baseload Plants Coming On-Line in 1991

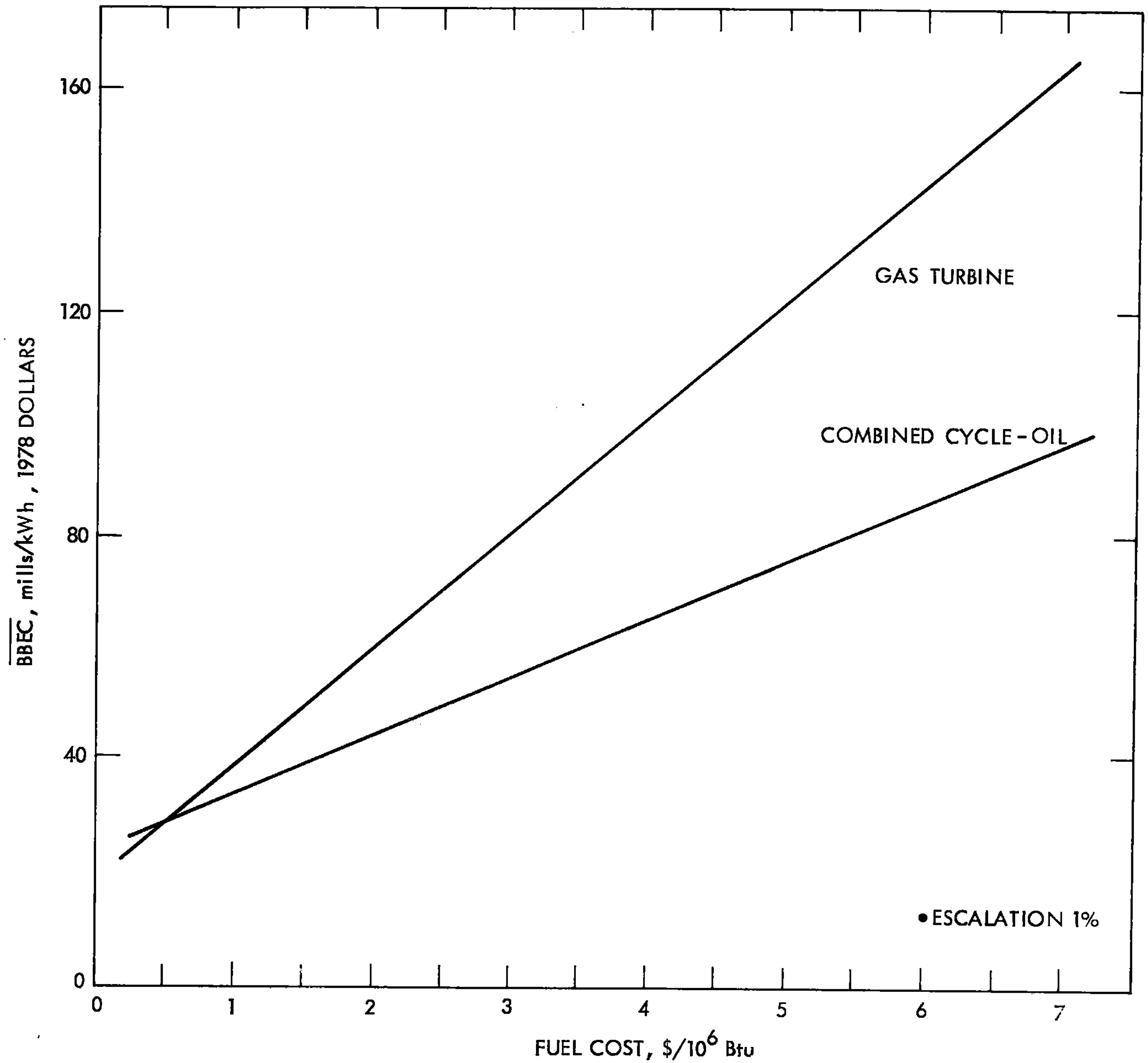


Figure 2-5. Levelized Bus Bar Energy Costs for new Intermediate Load Plants Coming On-Line in the Year 1986

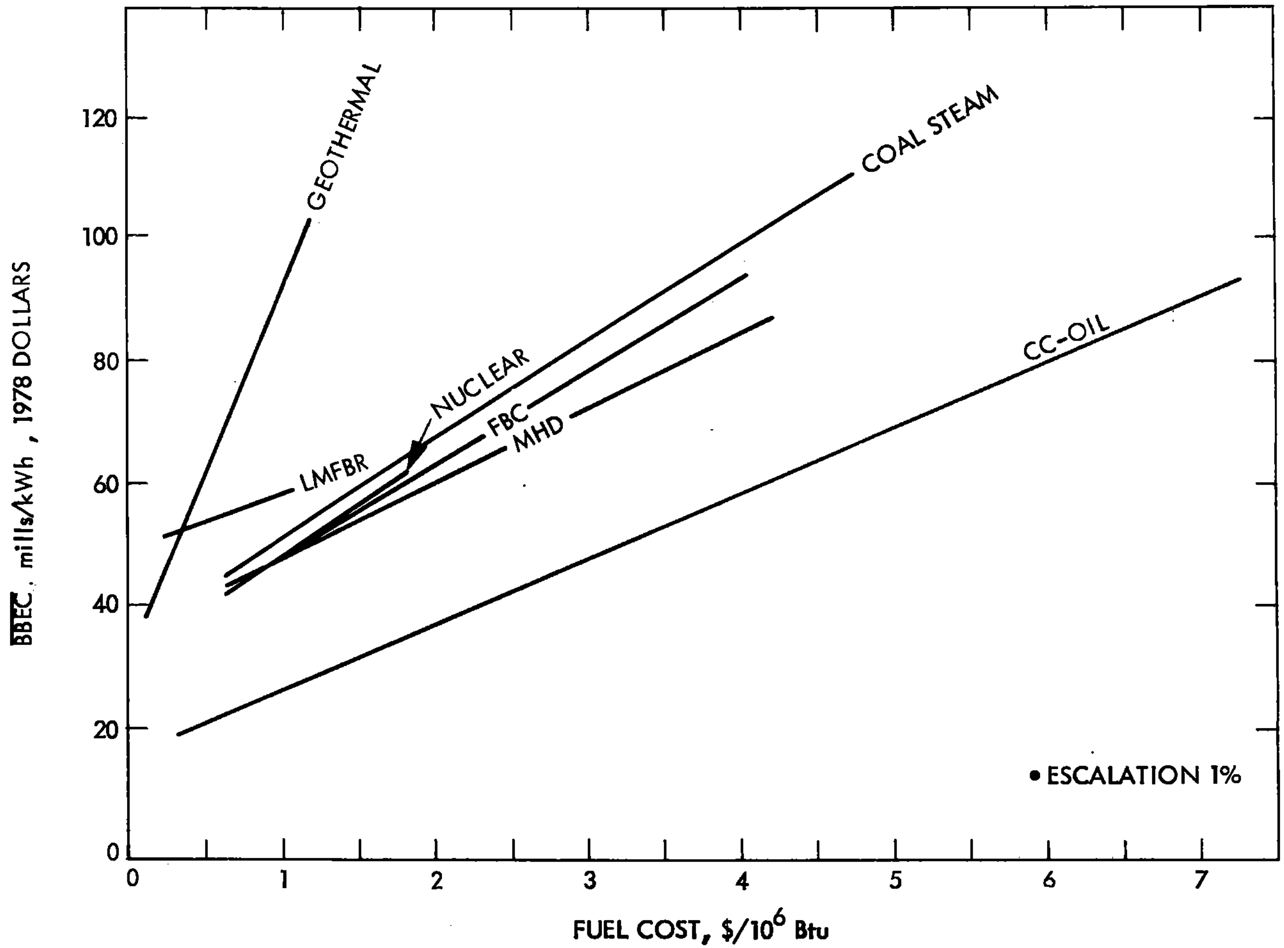


Figure 2-6. Levelized Bus Bar Energy Costs for New Baseload Plants Coming On-Line in the Year 1995

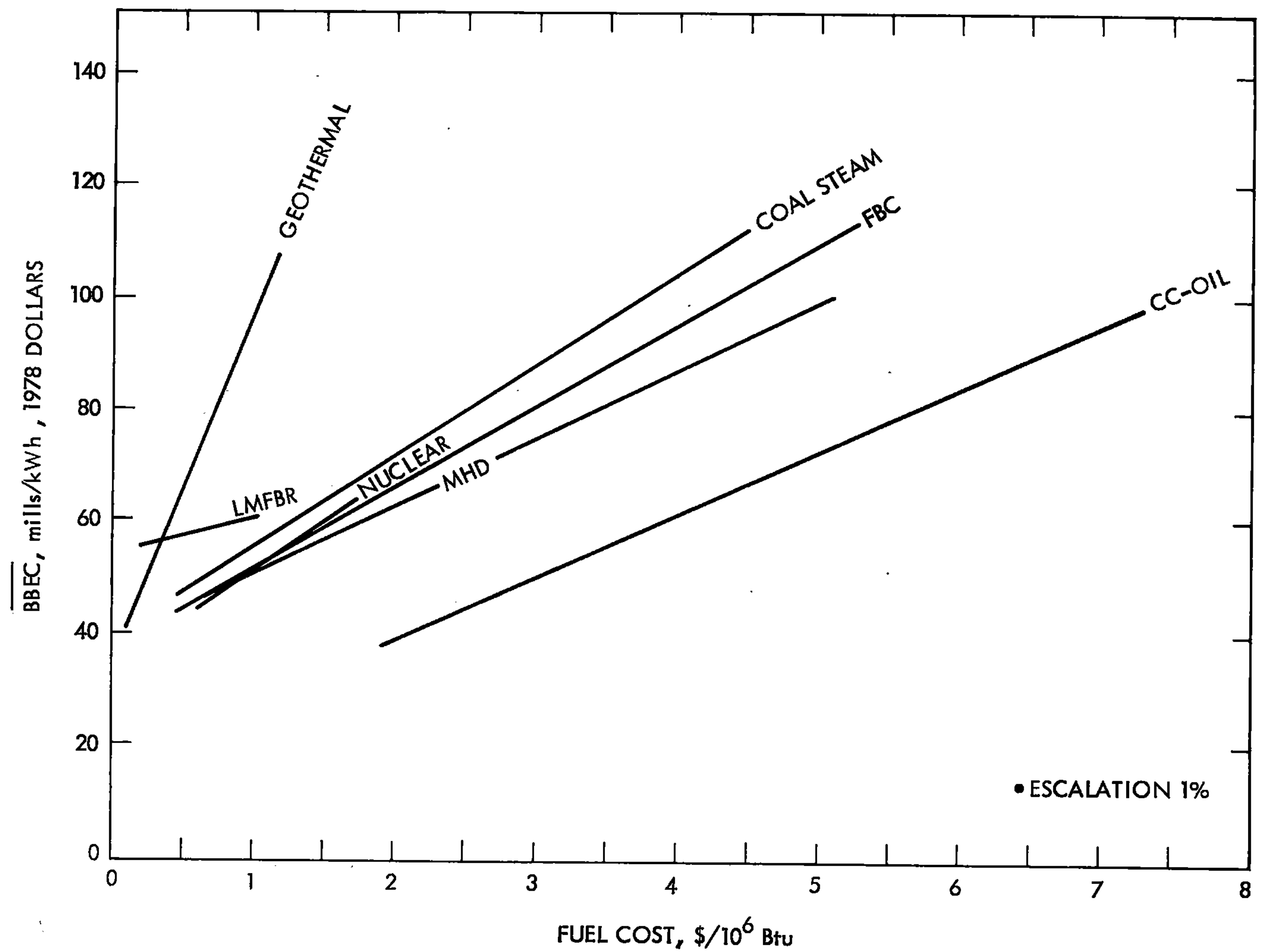


Figure 2-7. Levelized Bus Bar Energy Costs for New Baseload Plants Coming On-Line in the Year 2000

given in Table 2-2 with the maximum fuel price shown for each to be able to produce 50 mills/kWh power (1978$).

In studying these figures, one can see how sensitive energy cost is to the heat rate for a given technology. Energy costs of conventional plants with high heat rates are more sensitive to changes in fuel prices than thermally efficient systems. Advanced combined cycle plants with heat rates of 7000 Btu/kWh are least sensitive to increases in fuel prices, about 15 mills/kWh for each dollar per 10^6 Btu fuel price change. Magnetohydrodynamic (MHD) topping cycle plants with heat rates of 7400 Btu/kWh are also less sensitive to fuel price changes. These plants will not become available until after 1995 and may have capital costs exceeding those of combined cycle plants fired by synthetic high Btu gas.

Coal and nuclear LWR plants operate about 10,000 Btu/kWh. The sensitivity to price is approximately 20 mills/kWh for each dollar per 10^6 Btu fuel price change. Geothermal brine systems with poor heat rates of 28,000 Btu/kWh are in a different class.*

One can conclude that coal based plants will provide inexpensive electricity (40 to 50 mills/kWh or under) if the coal price remains low (under $\$2/10^6$ Btu) even with modest heat rate technology (10,000 Btu/kWh). Combined cycle oil fired plants will provide power at costs competitive with coal even at high prices ($\$6/10^6$ Btu) if the heat rate (7000 Btu/kWh) can be maintained for the plant life. Nuclear, geothermal, solar thermal and other technologies will have to compete at these costs if they are to penetrate the utility baseload power generation market.

In addition to busbar energy costs for a set of technologies, the reader may compare the previous figures to see the importance of fuel prices on a given energy cost.

Table 2-2 shows the maximum fuel prices for new baseload plants in order to produce 50 mills/kWh levelized busbar energy cost. For example, operators of new combined cycle plants coming on-line in 1986 must pay no more than $\$3.65/10^6$ Btu of fuel. Rising plant capital costs in 1995 and 2000 further reduce the maximum permissible fuel price to \$3.20 and $\$3.00/10^6$ Btu. All of the technologies have similar constraints, including magnetohydrodynamic (MHD) plants. Notice that for the capital costs given, LMFBR plants cannot produce 50 mills/kWh electricity even if the fuel is free. Because they will not be commercially available before 1995 at least, maximum fuel price conditions for LMFBR and MHD systems are not presented in Table 2-2 before 1995. On the other hand, coal steam plants are likely to be superceded by advanced fluidized bed combustion technology by 1995.

*The price of the heat may be determined contractually between the developer of the resource and the user. In some geothermal steam contracts, the developer of the field receives payment as a fraction of the electricity sold. The amount is based on the equivalent cost of fuel. If the power plant fails, the developer may not receive payments even though his wells continue to deliver steam.

Table 2-2. Competitive Fuel Price Required to Produce 50 mills/kWh Electricity for Various Baseload Central Generating Technologies

Technology	Fuel Price Conditions (1978$) $\$/10^6$ Btu				
	1986			1995	2000
	1% Escalation	2% Escalation	1% Escalation 5 yr Delay	1% Escalation	1% Escalation
Geothermal	0.35	0.30	0.30	0.30	0.25
Coal Steam	1.10	0.90	1.00		
Fluidized Bed Combustor	1.40	1.25	1.25	1.12	0.90
LWR	1.35	1.20	1.20	1.10	0.91
Combined Cycle	3.65	3.45	3.45	3.20	3.00
LMFBR				0	0
MHD				1.15	0.95

Since none of the fuel price forecasters anticipates long-term fuel price declines, nor do the engineering analysts foresee greatly improved heat rates beyond those already quoted, the present outlook is for electric energy costs to continue to increase.

Under these assumptions, the relative ordering of the plants does not change, only their energy costs and sensitivities to fuel price change.

1. Intermediate Load Plants

Many analysts believe that solar plants will first displace intermediate load plants. The analysis performed (Figures 2-5, 2-8 and 2-9) shows the energy costs for combustion turbines and combined cycle plants for intermediate loads in 1986, 1995 and 2000. Using the comparative approach, holding energy cost constant, Table 2-3 shows the maximum fuel costs for 50 mills/kWh electricity (1986$) for intermediate load plants.

Table 2-3. Competitive Fuel Price Required to Produce 50 mills/kWh Electricity. (Intermediate load plants with capacity factor of 0.3. Fuel price escalation is 1% above inflation)

	Fuel Price Conditions (1978$) $\$/10^6$ BTU		
Technology	1986	1995	2000
Combustion Turbine	1.55	1.35	1.25
Combined Cycle	2.35	1.90	1.80

2. Municipal Utilities

The test cases analyzed for a hypothetical southwestern municipal utility appeared to show little difference on the ranking of the technologies as fuel price was varied. For these cases, a zero income tax rate, a capital recovery factor indicative of increased proportion of debt capital, zero stockholder shares, and a municipal utility interest rate were assumed. These changes generated approximately 10% lower energy cost when compared with an investor owned utility at the same fuel price for the same plant technology. But neither the sensitivity to fuel price nor the rankings of capital costs for different technologies was affected. Table 2-4 shows the various taxes and fixed charge rate for municipal and investor owned utilities employed in the computation of energy cost.

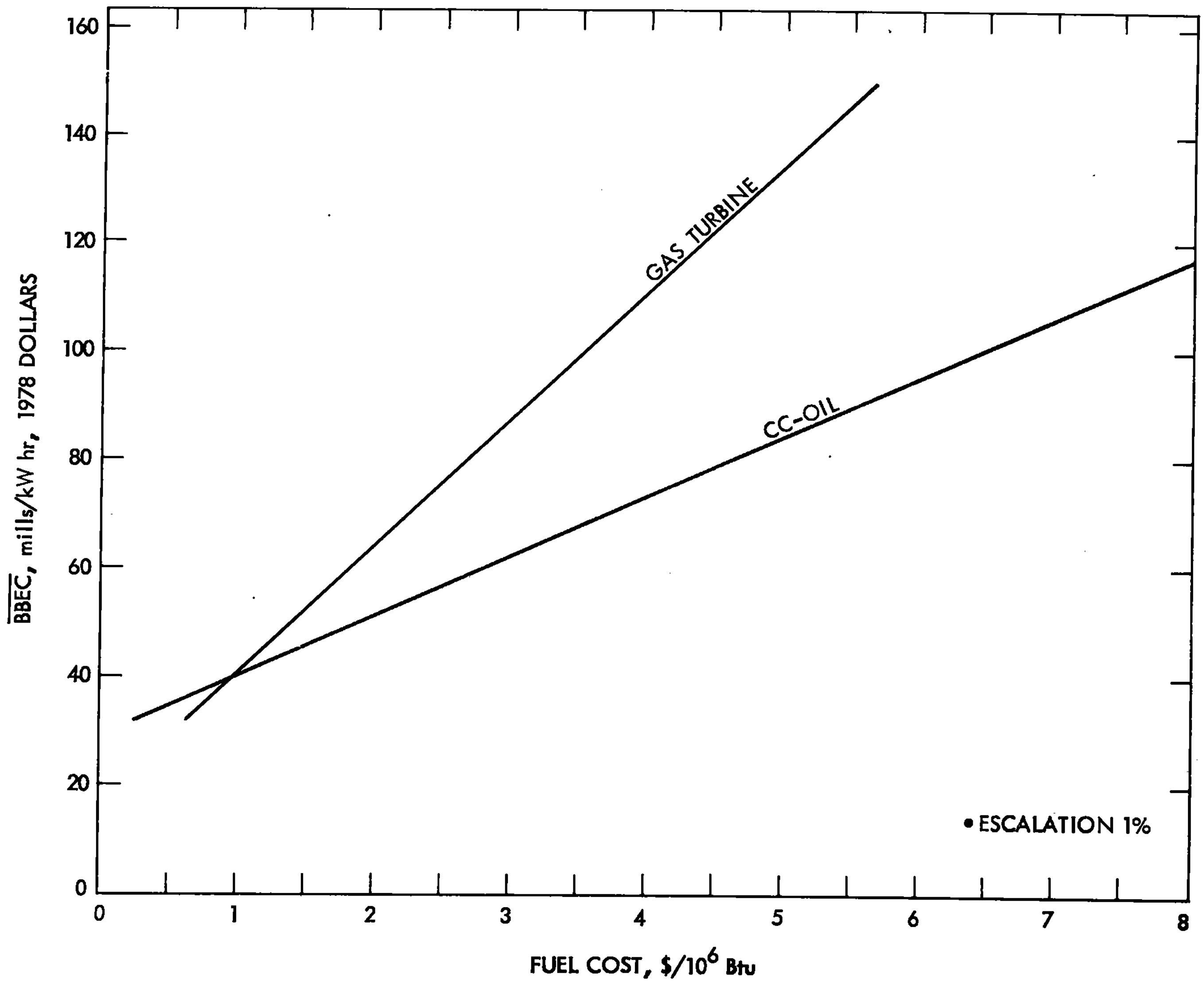


Figure 2-8. Levelized Bus Bar Energy Costs for New Intermediate Load Plants Coming On-Line in the Year 1995

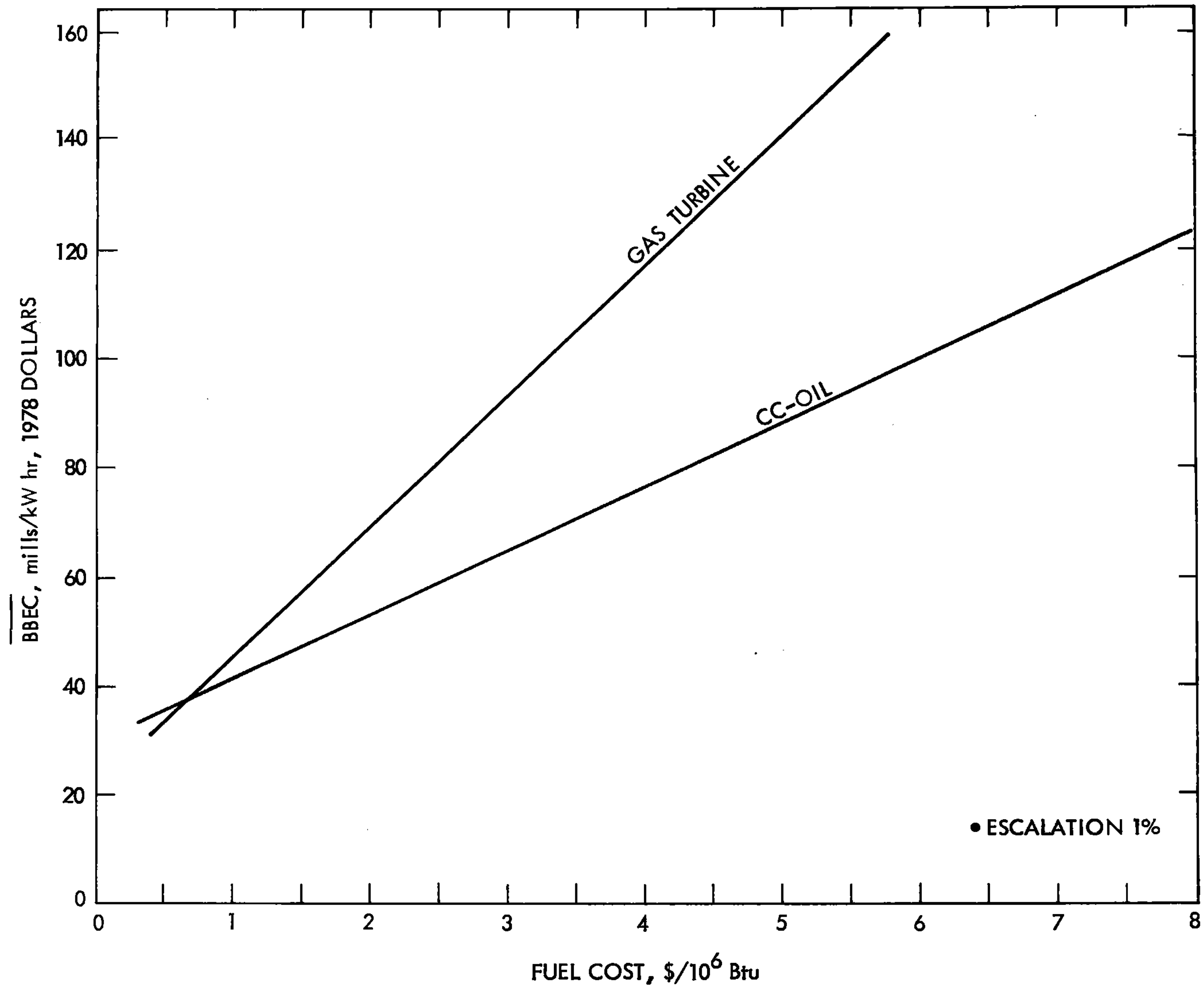


Figure 2-9. Levelized Bus Bar Energy Costs for New Intermediate Load Plants Coming On-Line in the Year 2000

Table 2-4. Financial Parameters for Utilities

	Investor Owned	Municipal
Income Tax Rate	0.46	0
Investment Tax Credit Rate	0.04	0
Insurance, Other Taxes, etc., Rate	0.025	0.11
Fixed Charge Rate	0.1511	0.1511

C. FUEL PRICE FORECASTS, ENERGY COSTS AND GOALS

The preceding figures have presented the busbar energy cost in 1978$ as functions of fuel price and technology. For the analysis, fuel price forecasts from five independent studies were examined. Kent Anderson,[34 35] DRI[56] and SRI[31] provide ranges of prices for coal and oil. However, as can be seen in Figure 2-10, none of the estimates reflect real price growth between 1985 and 2000. (That is, prices are assumed to increase at the general rate of inflation.)

The SYNFUELS[57] interagency task force study also provides a price range for coal and oil, and estimates a 1% above inflation price growth rate for these fuels. The FEA-PIES[21] study indicates no real growth in oil prices but a 2% annual price increase for coal. Figure 2-11 presents the envelope curves of the lowest and highest forecast prices for coal and oil. Coal costs are in the range of $\$0.69$ to $\$1.94/10^6$ Btu and oil costs are in the range of $\$2.50$ to $\$4.63/10^6$ Btu.

Energy costs were computed based on fuel prices shown in Figure 2-11. Figure 2-12 shows the baseload case for 60% capacity factor plants, using coal in fluidized bed combustors and MHD plants as well as oil in combined cycle plants. The energy costs range from 50 to 100 mills/kWh.

Intermediate load plants with 0.30 capacity factor, using combustion turbine and combined cycle technologies which burn oil, will have higher energy costs. This is shown in Figure 2-13. Combustion turbine energy costs may range from 100 to 200 mills/kWh and combined cycle costs range from 70 to 120 mills/kWh.

D. CAPITAL COST FORECASTS

This section compares six forecasts of utility power plant capital costs. A comparison of the results of the JPL analyses of utility data for 1986 is shown in Table 2-5 with the results reported by Joskow and Baughman[25] and studies performed by Electric Power Research Institute (EPRI)[24], Stanford Research Institute (SRI)[27], Arthur D. Little Co.[26], the former Atomic Energy Commission (AEC)[58], and in the document, National Energy Outlook (NEO)[21].

For coal plants, upper values in the ranges shown include precipitators, scrubbers for use with high sulfur coal, and cooling

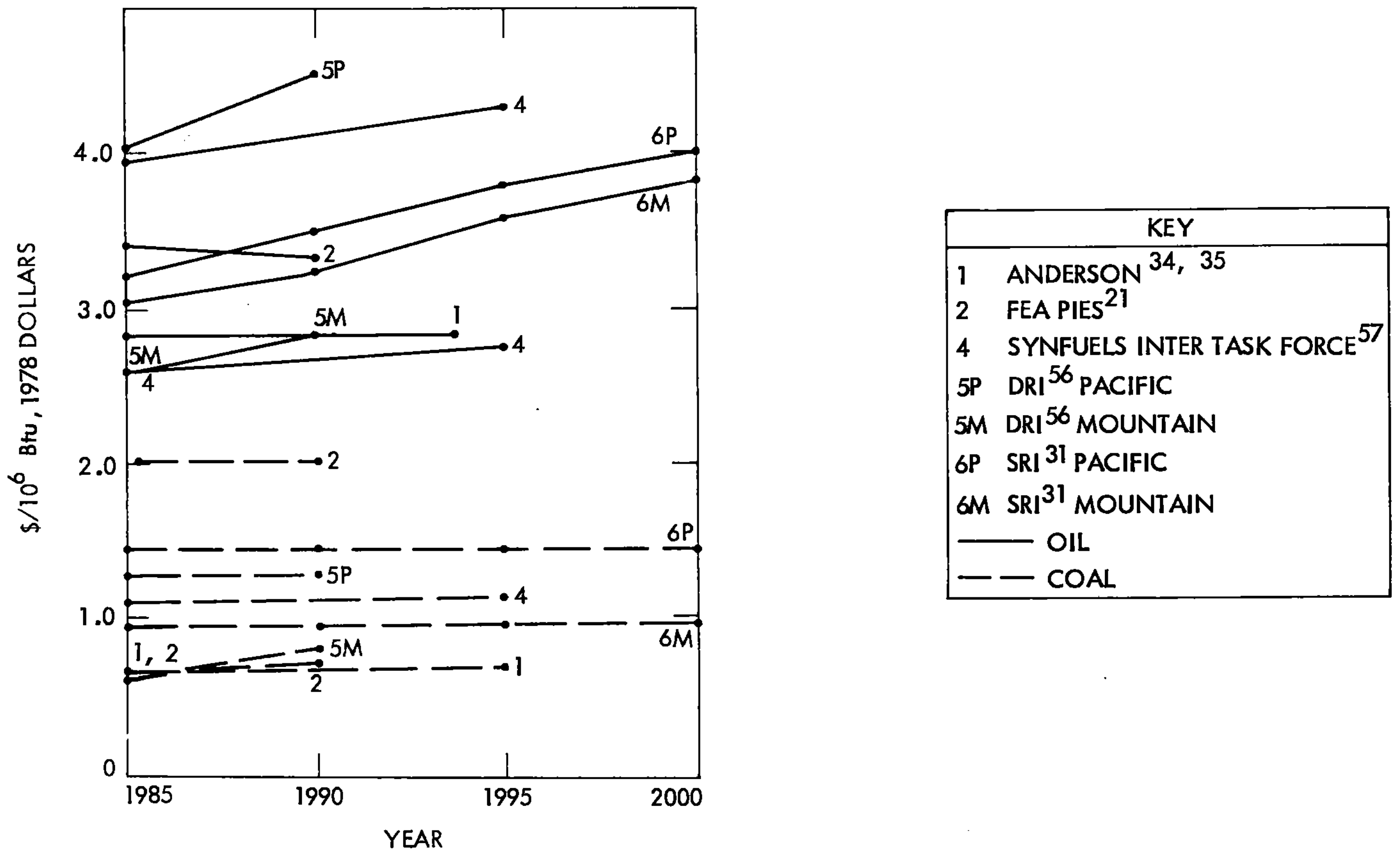
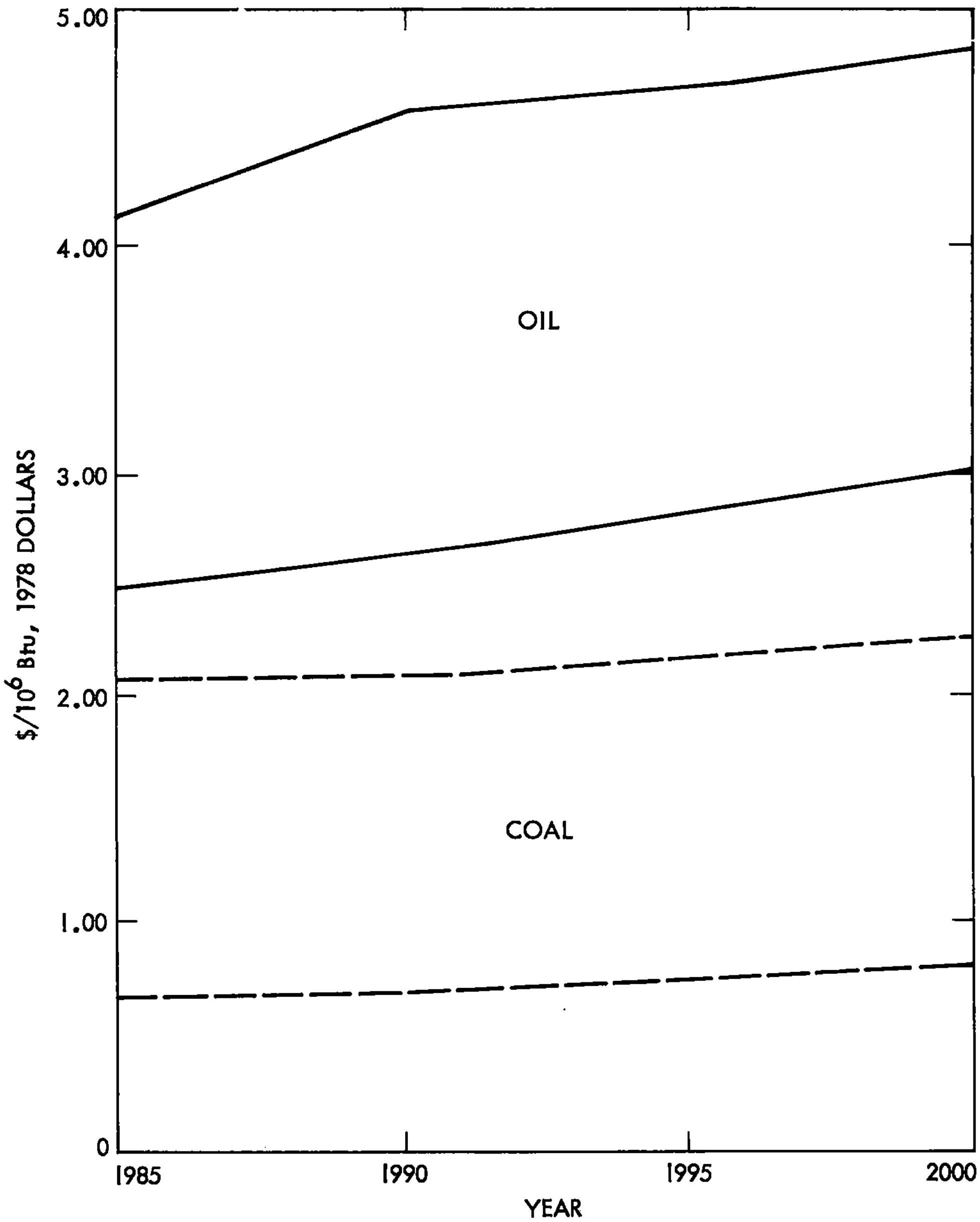
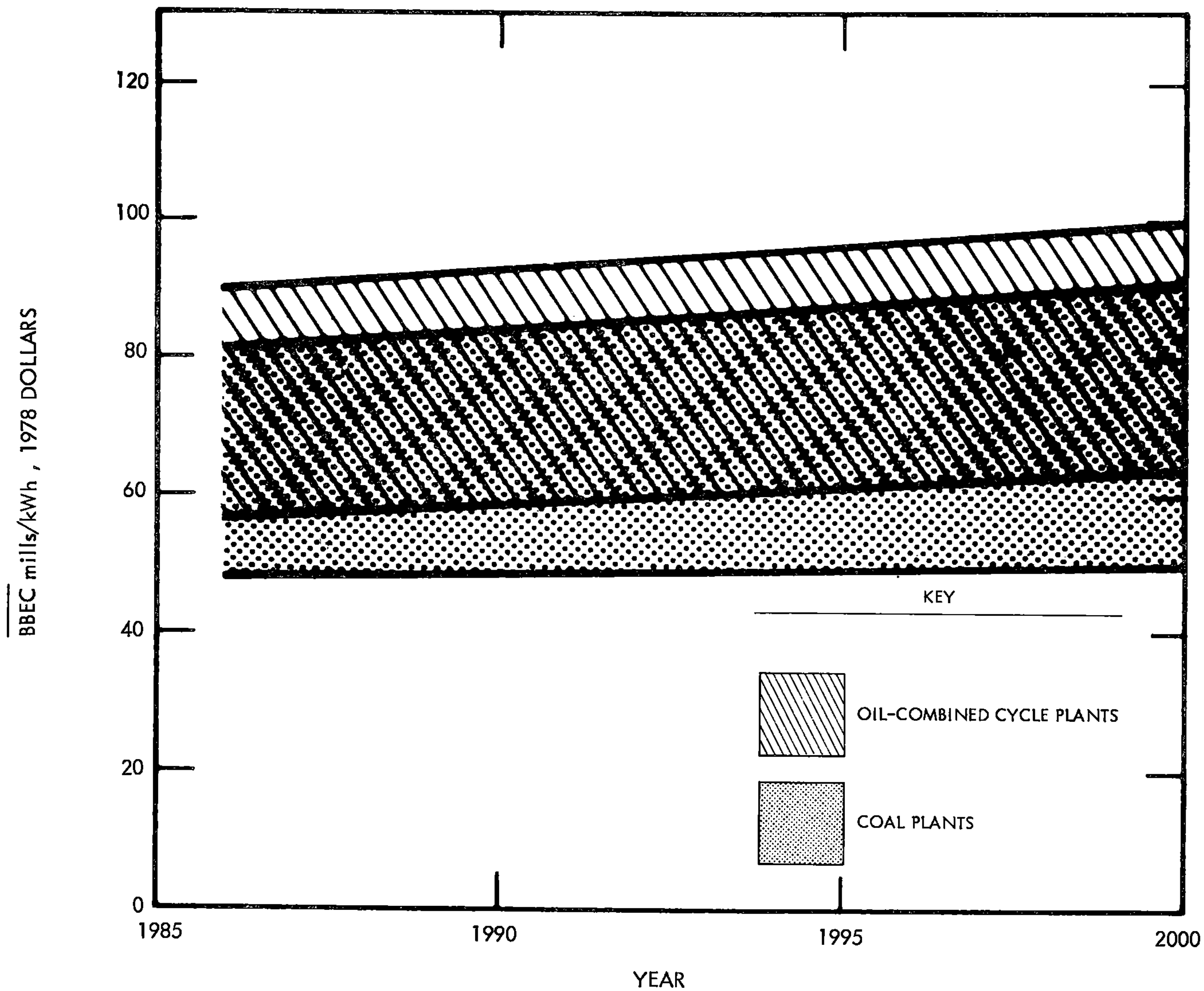


Figure 2-10. Fuel Price Forecasts



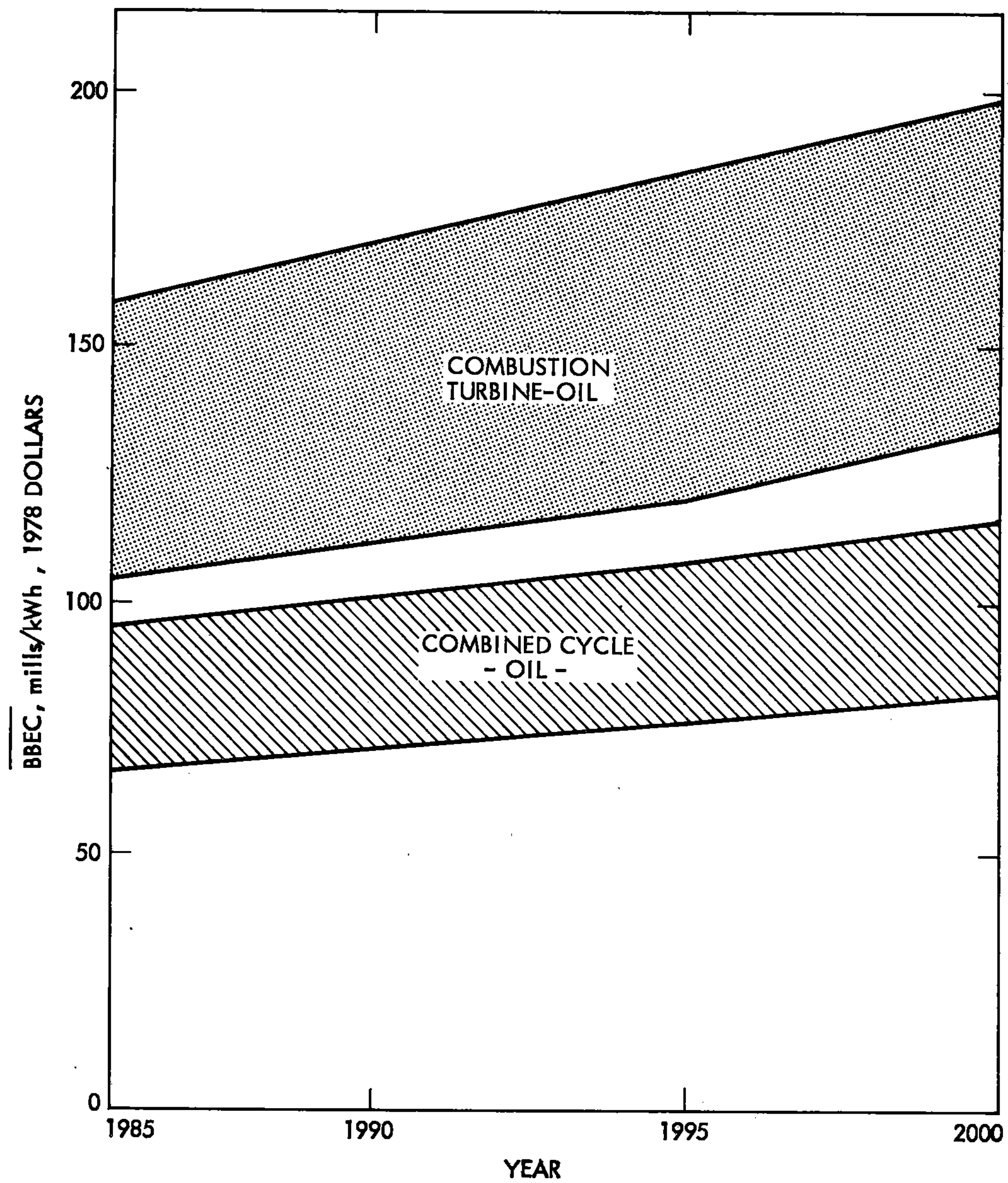
Note: These curves represent envelopes from Figure 2-10 showing highest and lowest prices of coal and oil found in the forecasts.

Figure 2-11. Fuel Price Forecast Extremes



NOTE: The plants come on-line the year indicated. Limits of the cost ranges are determined by fuel price forecasts (see Figure 10). The bus bar cost conversion rates are taken from Figures 2, 6 and 7.

Figure 2-12. Ranges of Bus Bar Energy Costs for New Baseload Plants



NOTE: The plants come on-line during the year indicated. The limits to the ranges are determined by the fuel prices as forecasted by the studies cited in Figure 2-10, and the energy conversion rates for these plants as shown in Figures 2-5, 2-8 and 2-9.

Figure 2-13. Ranges of Bus Bar Energy Costs for New Intermediate Load Plants

Table 2-5. Seven Capital Cost Forecasts
$/kW 1986 Startup, 1978$

	Coal	Oil	Nuclear	Gas Turbines
JPL Analyses of Utility Data	816	317	710	227
Joskow & Baughman[25]	426	368	585	152
Electric Power Research Institute (EPRI)[24]	739	464	878	319
Stanford Research Institute (SRI)[27]	344-438	287	631	140-206
Arthur D. Little (ADL)[26]	368-561	339-376	543-693	—
Atomic Energy Commission (AEC)[58]	401	362	482	—
National Energy Outlook (NEO)[21]	413-551	356	574-631	161

towers. All the values include interest during construction except those of SRI.

The capital costs for oil, nuclear, and gas turbines from these studies are comparable. The JPL estimate of $816/kW for coal plants is 10% higher than the next highest value reported by EPRI. The JPL nuclear plant cost estimate of $710/kW is 20% lower than the estimate made by EPRI. The JPL oil and gas turbine plant costs fall within the extremes reported by other investigators. It should be noted that the JPL analysis reflects cost estimates for coal and nuclear-fired steam plants as reported in the recent prospectuses of utilities in the southwest (Refs. 47-57). The JPL survey of utilities in the southwest indicate that capital costs for coal plants are greater than that for nuclear plants under construction. Other studies have developed cost data from sources such as the 1974 AEC Report.[58]

Anderson, Bowers, et al., of Oak Ridge National Laboratory (ORNL)[28] performed an interesting study to show the costs solar plants must achieve in order to compete in utility markets. They calculated energy costs as functions of fuel price, generation plant technology, and capacity factor for the year 2000. Converting all costs to 1978 dollars and fuel prices to $\$/10^6$ BTU, they assumed low sulfur coal available in the range of $28 to $49/ton and residual oil in the range of $14 to $21/bbl. They computed busbar electric energy costs at 39 to 62 mills per kWh for coal baseload plants (60% plant factor) and 62 to 112 mills/kWh for gas turbine plants (30% plant factor). The report concluded with an estimate of breakeven capital for solar plants (no storage) with no increase in energy costs. For peaking plants penetrating 2% of the utility system capacity, capital costs should not exceed $2700/kW. For baseload plants penetrating 35% of the total system generation, the maximum cost should not exceed $1000/kW.

Their results on expected energy costs agree closely with JPL cost goals study. However, the JPL analysis permits the reader to compute energy costs over a wider range of fuel prices and technologies. In the year 2000, for the same range of fuel prices used by Anderson and Bowers, coal baseload plants should produce electricity at 62 to 74 mills/kWh (Fig. 2-7). Intermediate gas turbine plants should produce electricity at 68 to 115 mills per kWh (Fig. 2-9). Note that the capital costs for solar plants for utility applications computed by Anderson and Bowers are of the same magnitude as the project cost goals.*

The energy costs of the JPL analysis shown in Figure 2-1 are also consistent with the independent estimate of mid 1990's levelized busbar energy costs by DeMeo and Bos.[60] They concluded that the levelized busbar energy costs for various fossil fired plants stated in 1976$ are as follows:

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*In their report, Anderson and Bowers worked in 1976$, which the authors converted to 1978$. A ton of coal is equivalent to 25×10^6 BTU, and a barrel of oil is equivalent to 5.8×10^6 BTU.

Coal steam	49 mills/kWh
Oil steam	94 mills/kWh
Combined cycle oil	81 mills/kWh
Oil steam-coal liquid	87 mills/kWh
Combined cycle coal liquid	74 mills/kWh
Solar thermal fossil hybrid	86 mills/kWh

E. IMPACT OF VARIOUS ENERGY FUTURES ON COST GOALS

The preceding actions compared engineering forecasts of hardware costs for power plant technology and fuel prices. One of the key underlying assumptions has been smooth, orderly changes in supply, prices, and demand. A more general view of energy supply and demand futures has been undertaken by numerous scholars in an effort to examine the impacts of changes in energy policies on various economic sectors. They suggest, among other things, that smoothly increasing fuel prices and inflation would occur only with no major disruption in supply or in the pattern of fuel consumption and with a continuation of existing subsidy, regulation, and growth policies in the energy sector.

While no one can predict the occurrence of disruptions, it is instructive to examine what might be the consequences of significant changes in U.S. energy policies as they affect the utilities and the goals for small solar thermal power plant technology.

Recent studies on utility[1,2,18,28,37] applications of solar energy in the southwest show little possibility for extensive solar penetration of the power market place until well into the 21st Century. This view is based on assumptions of continued growth of demand for electrical energy (at 4% per year or more), adequate coal, oil, and uranium available at smoothly increasing real prices and completion of the coal and nuclear power stations already committed or under construction.

Early in 1977, the Stanford Research Institute[1] suggested three alternative scenarios for the U.S. energy future: a low demand scenario, a reference scenario, and a solar emphasis scenario. The low demand scenario assumed a national energy consumption growth of 40% from 1975 to 2020; the reference scenario showed a 171% growth; and the solar emphasis showed 179% growth.

To achieve the reference scenario, the U.S. would have to acquire over one thousand nuclear plants of 1000 MW size, many located near population centers. It would require mining of western coal on a massive scale and construction of numerous gasification plants.

The situation in 2020 under the solar scenario came out almost the same. Solar reduced the impact of coal and nuclear plants by less than 10%, even though solar energy would become the most rapidly growing energy resource in the first and second decades of the 21st Century.

The rationale for low demand case was based on encountering a minimum environmental impact. Elements of both the solar scenario and the low demand cases could occur only if a strong national commitment were made in the 1980's to establish these as future national goals. The significant impact of implementing policies and regulations would be felt particularly in the Southwest U.S. where there are extensive coal and uranium resources, and where insolation is particularly high.

Weyant, in an independent economic modeling effort, also concludes that there will be no large scale market for solar generated electricity until the mid-21 Century, when the levelized busbar energy cost in 1977 dollars approaches 45 mills/kWh.[2] He concludes, however, if the nation places severe limits on the use of coal and/or nuclear fuel for reasons of health, environment, carbon dioxide buildup, nuclear safety and proliferation, then electricity prices may increase to a level to allow solar to compete on a large scale long before 2050, perhaps before 2000.

Commentators on national and global energy balances over the next 25 to 50 years present pictures of increasing global fuel scarcity and increasing public resistance to the intrusion of large central power plants on the environment and society.[5,23] These issues are not likely to disappear. On the contrary, the support for these arguments is likely to be more pervasive, particularly if variations in global energy supply seriously affect standards of living and national security.

The World Alternate Energy Scenario (WAES) Workshop of MIT[3] anticipates a major divergence of supply and demand for oil beginning before 1990 when demand will exceed supply. The impact of the oil shortfall will result in pressures on all the countries of the world to take active measures to conserve energy, to match energy supply with end use requirements, and to use whatever energy sources are available to them for immediate and local advantage.

One of the most articulate spokesmen for a national policy based on a decentralized energy technology is Amory Lovins. Lovins uses the term "hard path" to identify energy policies favorable to increased electrification by continued emphasis on conventional central power station technologies.[6-10] This path results in high economic costs accompanied by great environmental risks. The "hard path" is aimed at sustaining growth in energy consumption and minimizing oil imports by rapid expansion of U.S. utilization of coal, oil and uranium.

By contrast, the "soft path" presents a different view of the energy problem. It first examines the purpose of the energy need, and then attempts to develop the most efficient means to provide it. The characteristics of the soft path energy systems are described as: renewable energy flows, source diversity, matched in scale geographic distribution and quality to end-use needs, and amenable to mass production. The "soft path" would utilize solar energy for heating and cooling of buildings, wind for pumping and compressing air, conversion of biomass (crop, wood, and other organic waste) to liquid fuel for transport. Hydroelectric capacity and cogeneration would provide electric power. Using appropriate energy supply to meet end use needs and by employing technical fixes, Lovins contends that we can double our end use efficiency by the year 2000 without significantly altering our life style.

This section has outlined the diversity of views on energy futures in the U.S. From the standpoint of presenting the basis for estimating the energy cost of electricity in the Southwestern U.S. during the remainder of the 20th Century, this analysis has taken a conservative approach, reflecting smooth non-disruptive change in energy availability, and has set goals consistent with those conditions. It is quite possible that unpredictable events may occur over this period which suddenly make the goals of 1978 obsolete.

SECTION III

FINDINGS OF UTILITY INTERVIEWS

A. SUMMARY OF UTILITY GENERATION PLANS

Nine selected electric utility companies located in the Southewestern U.S. were studied in depth. A summary of the present electrical generation mix and the planned additions (by 1986) for the utilities are shown in Table 3-1.[44-45]

The utilities plan nearly to double their present generation capacity of 13,400 MW to 24,200 MW in 1986. The major fraction of the increase is expected to be nuclear and coal additions. In California, nuclear generation was expected to play a major role in future energy resource plans. For example, a report in 1976 by the California Energy Resources Conservation and Development Commission (CERDC) reported that sixty-four percent of the additions planned between 1985 and 1995 will be nuclear, 16% coal fired, 8% geothermal, 7% combustion turbine, 3% combined cycle, and 2% for hydro, fuel cells, wind, and direct solar combined. These additions total 51,000 MW.[18] The emphasis on nuclear, however, has changed more recently because of uncertainties in capability of managing nuclear wastes. As a result, the Sundesert and Wasco nuclear plants have been canceled in California and activity to promote others has virtually ceased.

Each utility has a different resource base, financial condition, and geography to consider in the management of the generation, transmission, and distribution of electricity. The differences among utilities and their outlooks are important and should not be overlooked. The remainder of this section presents some of the highlights of the differences and similarities found.

Table 3-2 presents some of the issues confronting the selected utilities and lists various factors which particularly affect the potential utilization of solar thermal electric systems in the future. The two California utilities (in the southern part of the state) are planning geothermal and oil-fired plants for future generation. They have relatively short transmission distances (under 100 miles) and operate under very severe environmental controls imposed by state and local governments. Earlier plans placed much greater reliance on nuclear power. The utilities interviewed indicated that they anticipate becoming partners in any future major power plant in the southwestern part of the state.

The Arizona and New Mexico utilities require transmission distances of 200 to 600 miles from mine-mouth coal plants and nuclear plants to urban load centers. Management of this network imposes severe logistic demands on these companies. In addition, problems such as the large amounts of land that need to be devoted to surface mining and plant facilities, water requirements and transmission, and increasingly severe environmental restraints appear to be becoming progressively more

Table 3-1. Present Generation Mix and Planned Additions by 1986 Selected Southwest Utilities[44-55]

SELECTED UTILITIES	OWNERSHIP	PRESENT GENERATION	GENERATION CAPACITY MW	PLANNING ADDITIONS (by 1986)	TOTAL CAPACITY MW
SAN DIEGO GAS & ELECTRIC CO. San Diego, California	Investor	17 steam 1 nuclear (20%) 20 combustion turbines	1921	Nuclear	2848
IMPERIAL IRRIGATION DISTRICT Imperial, California	Public Water District	1 steam 1 diesel 2 gas turbines 6 hydroelectric (purchase)	391	Geothermal	791
BURBANK WATER & POWER DEPT. Burbank, California	Municipal	6 oil - steam 3 gas combustion turbines purchase hydroelectric	251	Coal Nuclear Geothermal	384
EL PASO ELECTRIC CO. El Paso, Texas	Investor	8 oil steam 3 oil steam 1 combined cycle 2 coal (7%)	999	Nuclear Coal Combustion Turbine Pumped storage	1892
PUBLIC SERVICE OF NEW MEXICO, INC. Albuquerque, New Mexico	Investor	2 coal (13%) 5 natural gas steam 1 coal (50%)	893	Coal Nuclear Pumped storage	1897
SOUTHWESTERN PUBLIC SERVICE, INC. Amarillo, Texas	Investor	1 coal 15 natural gas steam 4 gas turbines	2559	Coal	4689
TUCSON GAS & ELECTRIC CO. Tucson, Arizona	Investor	1 diesel 1 oil steam 7 coal (7%-50%)	1348	Coal	2104
ARIZONA PUBLIC SERVICE CORP. Phoenix, Arizona	Investor	3 combined cycle 9 coal 7 oil steam 11 turbines	2561	Coal Nuclear	5143
SALT RIVER PROJECT Phoenix, Arizona	Agricultural Improvement District	5 hydroelectric 9 steam 7 combustion turbines 4 combined cycle 8 coal	2444	Coal Nuclear	4834

Table 3-2. Issues Related to Conventional and Solar Thermal Electric Systems

Selected Utilities	Factors Affecting Expansion of Conventional Power System	Factors Affecting Adoption of Solar Thermal Electric Systems
San Diego Gas & Electric	Hydro from Northwest will not be available after mid-80's. Sundesert has been canceled	Has experience in operating distributed power plants. Serves remote desert site of Borrego Springs.
Imperial Irrigation District	Participant in canceled Sundesert project; agricultural interests in Imperial Valley oppose coal plants.	Summer air conditioning load is compatible with solar electric systems output peak.
Burbank Water and Power	Participant in Sundesert. Hydro Power from Bonneville Power Authority in Northwest will cease to be available in the 80's.	Land for collectors unavailable near present generating station in urban area.
El Paso Electric Company	400-600 mile-long transmission distance between coal and nuclear plants on Indian lands. Currently, land usage rights and taxes under litigation with Navajo. Partners with other utilities.	Serves remote town of Van Horn — 120 miles south of El Paso; Hatch — 80 miles north of El Paso. Promising applications include solar dirven irrigation pumps. Pumping currently performed by gas or diesel engines.
Public Service of New Mexico	200-400 mile long transmission distance from coal and nuclear plants to load centers. Partners with other utilities in coal plants on Indian lands.	Leader of DOE project for repowering existing oil and gas fired plants with central receiver solar technology. Serves many remote sites.
Southwestern Public Service	Major part of generating capacity relies on natural gas (75% in 1978). Converting to coal in the 80's.	Serves remote areas over 45,000 mi^2 service area. If a a distributed system was available, the utility could have a decreased need for distribution lines.
Tucson Gas & Electric	340-420 mile-long transmission distance from coal generating plants to load center. Coal, water and planned plant sites are located on Navajo land.	Has experience in distributed power systems serving load centers in Tucson, Ft. Huachuca, and copper mines 35 miles from urban load center.
Arizona Public Service	Expensive pollution control equipment required on planned coal plants. 200-300 mile-long transmission from nuclear and coal plants. Partners with other utilities in coal plants on Indian lands.	System reliability might increase if distributed plants were available close to Phoenix.
Salt River Project	Long transmission distances from planned coal and nuclear plants. Partners with other utilities in coal plants on Indian lands.	System reliability might increase if distributed solar plants were available in service area.

difficult to handle. These factors do not yet show up in the power cost or reliability forecasts, but they are of serious concern to the utility planners.

In general, all of the utilities indicated that they would adopt solar thermal electric systems as an energy option once they are demonstrated to be technically feasible and economically competitive.

Two of the utilities; i.e., San Diego Gas and Electric Company and Tucson Gas and Electric Company, have had considerable experience in the past operating small dispersed units of oil and gas-fired turbines. These units are now primarily used for intermediate and peaking service. This type of operating characteristic also appears to be particularly suitable for solar thermal electric power plants.

B. INSTITUTIONAL AND POLICY ASPECTS

The utility, a regulated monopoly, is franchised by a state to provide electric power in a particular region. Typically, it must provide power to all customers on demand, or it endangers its franchise.

Typically, the price this monopoly may charge is regulated by a state's Public Utilities Commission on the basis of evidence as to cost and rates of return. Because of rapidly changing fuel prices, especially after the 1973 oil embargo, the utilities have been able to pass on the increased costs to the consumer. Conversely, as fuel costs decrease, the savings are supposed to revert to the consumer. As a result, the utility has effectively insulated itself from the escalation of fuel prices.

One of the most difficult financial requirements for a utility involves the raising of new capital for power plant construction. In order to compete for debt and equity capital on the financial market, high interest rates must be assumed. In most states, the utility may not pass this interest cost on to the consumer in the form of higher electric rates until the PUC allows the new plant into the rate base. In California, a plant cannot be part of the rate base until power is produced. The plant's owners, therefore, must continue to pay interest charges on the borrowed amounts until the plant comes on-line. A light water reactor plant which takes 10 years to complete may accumulate as much as 30% of the construction and hardware costs in interest and escalation. Some states are less severe on the utilities in this respect. For example, Arizona has begun to permit utilities to enter partially completed plants into the rate base two years before commencing commercial operations, thereby cutting the interest cost by almost one-third.

The major economic advantage of solar plants is in the area of fuel savings. However, the price differential for fossil fuels does not yet appear to be large enough to insure rapid pay-back of additional capital invested in solar. In fact, solar plants will be capital intensive, requiring the utility to raise as much capital per peak kilowatt of capacity or more, as it requires for a coal-fired or LWR plant.

To reduce capital costs of new plants, federal land could be made available to the utility as a solar plant site, on favorable terms as compared to acquiring rights to privately owned land. The value of other incentives to make solar more attractive than conventional systems requires further study.

All of the southwestern utilities plan to increase generating resources by a factor of approximately two by 1986. The Arizona and New Mexico utilities plan on coal and nuclear plants to supply this power, and have made substantial commitments to building of these plants. In the early 1980's coal and nuclear sources are expected to account for 75% of the plant capacity. California utilities face a less certain future, since the 1978 regulatory climate is highly unfavorable to additional nuclear plants. Potential public acceptance of coal plants is also not encouraging for this area.

In Arizona and New Mexico, the Palo Verde nuclear complex and mine-mouth coal plants presently under construction in Farmington, Four Corners, Page, and Springerville are scheduled to come on-line during the 1980's and early 1990's. These plants, as well as those already in operation, face potentially tougher operating and licensing restrictions by the Navajo Nation, the state, the Environmental Protection Agency, and the Nuclear Regulatory Commission. These constraints may require extensive redesign and retrofit of equipment for pollution control, and stretchouts of the times required for certification of plants under construction. The utilities also face renegotiation of leases, coal contracts, and taxation of facilities on Indian Lands, which all require extensive litigation. The outcomes may cause large and abrupt fuel price increases, large penalty payments and interruptions of operations. The interviews with utility planners indicated that a number of specific instances of these events have already occurred. These problems are not isolated circumstances, but rather evidence of the impacts of energy development on the environment, as well as dissatisfaction by some members of the public.

Because of uncertainties in the future, it would be a serious error to rely solely on a few technological alternatives. There are numerous problems that affect the future availability and reliability of supplies of primary fossil fuels. Utilities are very susceptible to fuel supply interruptions, vandalism to long transmission lines, and delays or cancellations of new coal or nuclear central power plants. Decentralized power plants using renewable resources represent a degree of insurance against these interruptions. If solar thermal electric systems are to be adopted by the U.S. utilities as a response to these difficulties in the 1985 to 2000 year time frame, the costs will have to be economically competitive with the alternatives indicated in this report.

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