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Energy and Environment Division

Analysis of the California Energy Industry

Energy Analysis Program

January 1977

Lawrence Berkeley Laboratory University of California/Berkeley

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ANALYSIS OF THE CALIFORNIA ENERGY INDUSTRY

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SUMMARY

The energy supply system for California is an integral part of the state's economy, both in terms of energy as a commodity and in the economic effects of expanding requirements for new capital and manpower in the energy sector. It is this notion of an expanding energy system that forms one of the motivations for many of the energy policy discussions and formulations currently taking place. Some of the questions to be addressed are: If the energy system is to expand, by how much, and in what particular areas of supply? What are the policy ramifications of certain changes as opposed to others? What are the major economic effects of changes in energy supply system plans? The purpose of this study is to 1) describe quantitatively the California energy industry and its relationship to the California and U.S. economies, 2) provide the analytic capability for determining the direct and indirect employment and income impacts resulting from a given energy future for California, and 3) demonstrate and test the methodology with scenarios that embody varying combinations of conventional energy technologies, new energy technologies and energy conservation measures.

The methodology we have developed is generally applicable to any set of specified changes. In this report we select three alternative energy futures for California in order to quantify their resulting economic impacts.

THE PRESENT CALIFORNIA ENERGY INDUSTRY

The present California energy industry is increasingly dependent upon imported energy (both domestic and foreign). The trend over the past decade shows a peak in production within California of both crude oil and natural gas in the latter part of the 1960's. The production of both these fossil fuels has declined since 1968 at annual rates of approximately three and nine percent respectively. Meanwhile, in 1970, the sales of electrical energy surpassed the instate production. This differential has since grown larger; in 1975 sales exceeded production by almost 14 percent.

In relation to the overall California economy, the present energy industry accounts for about 1.4 percent of nonagricultural employment, and provides about 3.5 percent of the Gross State Product. Wages in the California energy industry run about 1 percent higher than for the national energy industry, while the work week is about 2 percent shorter. In terms of labor intensity the energy sectors range from 4.7 to 14.3 employees per million dollars output whereas the median for all industries is 27.5. Because the energy sectors are presently among the lowest twenty percent in labor intensity, large changes in output from these sectors are required before significant changes in the level of employment are felt.

FUTURE ENERGY SUPPLY SYSTEMS: AN ASSESSMENT METHODOLOGY

In order to quantify the employment and income impacts of future energy systems,we have developed an energy supply model for California and linked it to an input-output (I-O) model of the California economy. This energy supply model simulates the construction and operation of energy resource extraction, transportation, and conversion facilities. It calculates capital and operating requirements, including materials and fuel, for these facilities. The indirect manpower and income effects are then estimated by transforming these requirements into inputs to the I-O model. The I-O model represents the economy as a matrix of purchases and sales among all producing and consuming sectors. The interdependence among sectors is explicitly accounted for so that the impact of changes in the production of any given sector can be traced to all the other sectors. Among the impacts calculated by these models are fuel requirements, capital and manpower needs for the construction of new energy facilities, the indirect manpower required for the supply of construction materials and some of the costs and manpower associated with the operation and maintenance of these facilities.

We have developed, in conjunction with the CERCDC staff, three scenarios of future energy growth in California as a demonstration of this methodology for comparative impact analysis. While these scenarios are not forecasts on our part of future energy supply, they do set out three

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alternative energy futures in order to display their relative impacts. The first scenario is based on the electric utilities' schedule for adding new generating capacity and on published forecasts of oil and gas supply and demand.

The second scenario differs from the first by emphasizing new electricity supply technologies and a decreased availability of natural gas. These new electricity supply technologies include wind turbines, solar-thermal and waste-fired power plants. This scenario also postulates an increased emphasis on geothermal energy rather than nuclear fission for electricity generation, and the deployment of active solar heating devices in residential buildings.

The third scenario was developed based upon the first scenario, with modifications to account for the implementation of the following energy conservation measures: 1) delamping in commercial buildings, 2) retrofit ceiling insulation in residential buildings, and 3) a program for housing construction consisting entirely of passive solar houses. We have estimated the energy savings resulting from each of these programs and translated these savings into a reduction in the number of new energy supply facilities from those required in the first scenario.

The scenarios required the development of a data base that included construction and operational requirements, construction lead times, capital and manpower flows, and other related details. For conventional facilities, we used the data supplied in the Energy Supply Planning Model developed by the Bechtel Corporation. Data necessary for both new technologies and for conservation measures were collected as a part of our study.

Information on the new technologies used in the second scenario was derived from the available literature. Data for the conservation measures required estimates of energy savings and capacity savings where applicable, as well as materials and manpower needs. The delamping program of the third scenario involves reducing the lighting level in commercial buildings by replacing a portion of the existing fluorescent tubes with nonluminous Phantom™ tubes which require no other circuit modifications. At the completion of the five-year delamping program there would be an annual savings of 10.5×10^9 kwh.

For the passive solar housing program, we postulated a change in building codes for new residential construction beyond present insulation and glazing requirements. In addition, the physical orientation and thermal mass of a building are also designed to maximize solar heat gain during the winter and to minimize it during the summer. The additional costs due to extra insulation and double glazing required for such housing are nearly offset by the calculated savings in the reduced first cost of heating and air conditioning units. We estimate that a passive solar house constructed to these standards would have a heating and cooling load of 40 percent of that of a house built to present code standards. For a typical single family dwelling (averaging 1450 ft^2) the annual savings could amount to 28×10^6 BTU for gas heated homes, or 4600 kwh for electrically heated homes. The savings in air conditioning energy requirements are nearly 1600 kwh per year, which can be translated directly into on-peak electricity demand periods during the summer. Such a housing construction program of approximately 205,000 units per year, all built to the new code requirements, would result in incremental annual energy and capacity savings of 3.1×10^{12} BTU of natural gas, 380×10^6 kwh of electricity, and 280 MWe capacity. By 1991, the yearly savings would amount to 47×10^{12} BTU of natural gas, 5.7×10^9 kwh of electricity and an accumulated capacity savings of 4200 MWe.

The third conservation measure is retrofit ceiling insulation in that portion of the existing housing stock that are insulatable. For gas heated houses this would generally mean a change from virtually no insulation to R-19 level insulation. For electrically heated houses, this would mean upgrading insulation levels from a present average of R-7 to R-19. Computer simulations of the thermal integrity of buildings with various levels of insulation and under typical thermal loads indicate that there could be a 35 percent savings in gas used for space heating in a single family dwelling following this retrofit program; the savings in electricity consumption would be approximately nine percent in electrically heated dwellings. There are comparable savings in air conditioning. If such a retrofit program were implemented over the five-year span assumed in this study, the annual statewide savings would be nearly 100×10^{12} BTU of natural gas and 440×10^6 kwh of electricity at the end of the program.

Table I gives estimates of energy savings and capacity reductions for the three conservation programs.

Scenario Analysis

Several differences emerge from the analysis of direct and indirect resource requirements embodied in each scenario. First, the overall rate of increase in primary energy demand over the next twenty years changes from scenario to scenario. For the first scenario the annual increase is 2.6 percent. Most of this increase is contained in a continued growth of the demand for oil, and an increased emphasis on nuclear fission for electricity generation. The second scenario has the lowest annual growth rate, at 2.0 percent. Although demand for oil here also increases until the mid-1980's, gas availability is seen to decline with some, but not all, of this decrease accounted for by active solar heating of residential buildings. A second major change between the first and second scenarios is the assumption that there will be no new nuclear generating capacity beyond that presently under construction. In its place, we postulate an increased emphasis on geothermal power for electrical generation. In terms of cumulative resource use, the consumption of nonrenewable resources (natural gas, coal, oil, uranium and geothermal heat) is 11 percent lower in the second scenario as compared to the first. The major differences here are a 66 percent decline in nuclear fuel requirements and a 31 percent drop in natural gas. The twenty-year cumulative energy requirments for the three scenarios are shown in Fig. I.

A direct comparison of the first and third scenarios shows the effect of the energy conservation measures postulated in the third scenario. For nonrenewable resources there is a four percent difference in the total primary energy requirements for the twenty-year period. The major components of this change are a six percent savings in natural gas, a 42 percent drop in coal requirements (accounting for savings in SNG as coal), and about an eight percent decline in nuclear fuel requirements.

The capital and manpower requirements for the three scenarios, aggregated to five-year periods, are shown in Table II. A significant portion of the capital and manpower in the second scenario is expended on active

Table I

Estimates of Energy Savings and Capacity Reduction

	Cumulative Energy Savings						Cumulative Savings in Generating Capacity (MWe)		
	Natural Gas (10^{12}BTU)			Electricity (10^{9}kwh)					
	to 1981	to 1986	to 1991	to 1981	to 1986	to 1991	to 1981	to 1986	to 1991
Delamping	0	0	0	26.2	78.7	131.3	3080[a]	3080[a]	3080[a]
Retrofit Insulation[c]	248	745	1242	1.1	3.3	5.5	0	0	0
Passive Solar Housing[c]	39	155	349	4.8	19.2	43.1	1400[b]	2800[b]	4200[b]
Total	287	900	1591	32.1	101.2	179.9			

a. Base load.

b. Peak load.

c. These programs, taken together, save natural gas equivalent to the projected output from two synthetic natural gas (SNG) plants (total 141 X 10^{9} ft^{3}/yr).

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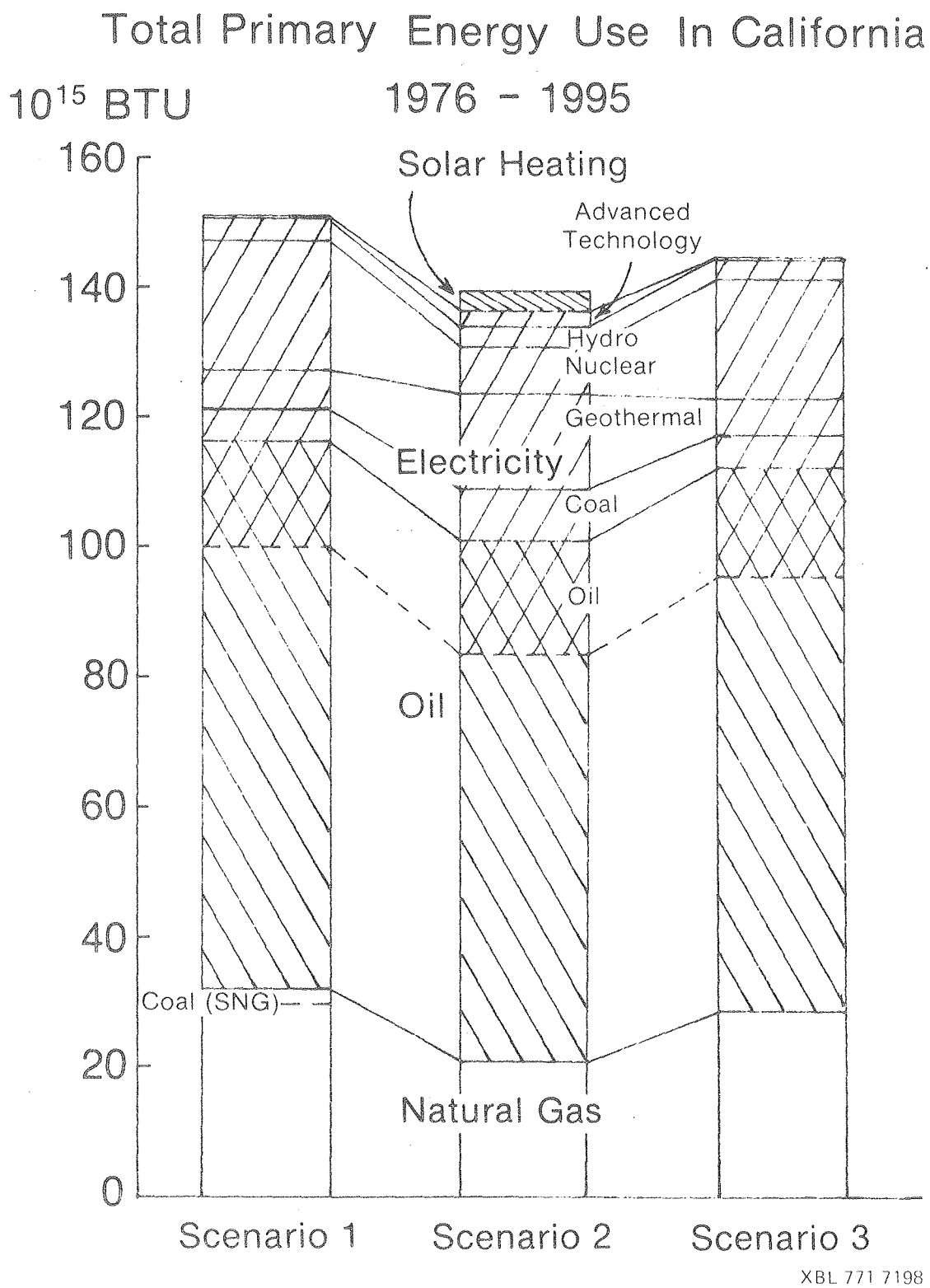

Figure I

Table II

Summary of Construction and Operation Requirements (1976-90)

		Capital (10^6 1974 $)		Manpower (Man-years)				
		Construction	Operation	Construction	Operation	Indirect	Total	Average Annual
Scenario 1	1976-80	10,131	7,073	101,900	259,800	189,000	550,700	110,100
	1981-85	22,544	7,906	203,400	274,500	374,600	852,500	170,500
	1986-90	15,239	9,116	177,900	300,000	282,800	760,700	152,140
	Total	47,914	24,095	483,200	834,300	846,400	2,163,900	144,300
Scenario 2	1976-80	19,051	7,470	258,500	298,300	330,700	887,500	177,500
	1981-85	17,712	9,466	224,200	382,700	298,800	905,700	181,100
	1986-90	18,141	10,962	208,000	450,100	302,700	960,800	192,160
	Total	54,904	27,898	690,700	1,131,100	932,200	2,754,000	183,600
Scenario 3	1976-80	9,423	6,948	94,800	258,300	180,600	533,700	106,740
	1981-85	18,283	7,616	172,800	267,800	337,600	778,200	155,640
	1986-90	15,097	8,763	177,000	290,700	284,200	751,900	150,380
	Total	42,803	23,327	444,600	816,800	802,400	2,063,800	137,600

solar heating devices. These devices are installed at a uniform rate over time, making the capital and manpower flows more uniform than those of the first scenario. The large unit sizes and the non-uniform distribution associated with some of the facilities in scenario 1 and 3 appear to introduce significant fluctuations in capital and manpower requirements over the period 1976 to 1990.

In terms of the overall state economy, the capital requirement for the construction of new energy facilities averaged over 15 years is about 14 percent of the 1974 value of Gross Private Capital Formation in California. The difference, on an annual basis, between the first and second scenarios is 500 million dollars, or two percent of the state's Gross Private Capital Formation. A comparison of the first and third scenarios gives a smaller value, amounting to 1.4 percent of the Gross Private Capital Formation. The difference in the annual average contribution to Gross State Product between the first and second scenarios is $400 million; between the first and third scenarios it is close to $100 million. These differences should be compared to an estimated 1974 Gross State Product of $157 billion.

Future demand for manpower for each scenario is also summarized in Table II, which indicates that less than two percent of the present California labor force of nearly 9.5 million would be absorbed in the energy sector. More importantly, the difference in the average number of persons required per year between the first and second scenarios is 39,000, or less than 0.5 percent of the labor force. When compared, however, with the average number of new, nonagricultural jobs created annually in California (about 210,000 per year) these additional jobs make a large contribution to employment growth. Our analysis of resource requirements for each scenario stops at 1990. Perhaps some of the differences between the scenarios might decrease if the analysis was extended another five or ten years. In any event, our results show that one can formulate an energy supply scenario which is more labor intensive than another. This does not imply that energy policy can or should be used to make employment policy.

IMPACTS OF ALTERNATIVE INVESTMENTS

We examined some of the tradeoffs between the three energy conservation programs, and the energy facility construction programs. The delamping program could result in savings of 131 X 10^9 kwh of electricity over a fifteen-year period, and would result in a reduction in capacity requirement of 3080 MWe by the mid-1980's. This would remove the need for two 1100 MWe nuclear power plants, and one 800 MWe coal-fired power plant. These power plants would have required $1.2 billion (1974 dollars) and 39,000 man-years of labor whereas the delamping program would require no additional resources. The passive solar program reduces the need for peak-load generating capacity by 4200 MWe in 1990, due mainly to a reduction in air conditioning load. A comparison of direct and indirect manpower required to construct new peaking capacity (using gas turbines) with the manpower required for the passive solar heating program indicates that the solar heating program would require 300 fewer man-years annually than the construction of new peaking capacity. The capital savings over this fifteen-year period resulting from the passive solar housing program would be $510 million. Natural gas savings accruing from both the passive solar housing program, and a program of retrofit insulation would amount to 1.6 X 10^{15} BTU over the next fifteen years. This is slightly more than be projected output of two synthetic natural gas (SNG) plants proposed as one source of additional supply for California. Cancellation of these plants would reduce capital demand by $1.5 billion (1974 dollars) and would reduce demand for labor by 23,000 man-years.

The net impact of the conservation measures investigated in this study would be a significant savings of energy, accompanied by a reduction in capital requirment in the energy sector. The demand for construction manpower would also be lower. In general, the overall economic effects will depend on how these resources are used in other sectors of the economy, which would in turn depend on future levels of economic activity.

Several important limitations of this study should be kept in mind. First, there are limitations in both the accuracy and availability of data. A major portion of the data on materials and manpower were developed in 1974 and these reflect the engineering estimates made at that time. The uncertainties in these data range from ± 10 to ± 50 percent. Data on new

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technologies are even less reliable, since they are based on engineering estimates or experience with pilot plants. The data pertaining to the energy conservation measures investigated here have similar reliability limitations due to the nature of our assumptions. Second, we have assumed linearity in both energy supply processes and in economic structural relationships that may not be an accurate reflection of either. These assumptions do not take into account economy of scale considerations, or improvements in technologies that may take place over time. Similarly, the input-output model of the economy is based on the structure of the California economy for 1972 and thus cannot account for structural changes that could take place in the fifteen-year period used for our study. Finally, the boundaries imposed in this study can have an important effect upon the results. Average direct resource requirements could change as the time periods are extended beyond 1990. Similarly the extent to which indirect effects are included could alter the magnitude of some of these effects.

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I. INTRODUCTION

A major consideration facing California energy policymakers is the need for a more detailed understanding of the relationship of the California energy industry to the rest of the California economy. While it is obvious that expansion plans in the energy industry affect the rest of the economy, the magnitude and types of impacts that alternative plans may have are not clear. Quantitative assessments of the consequences of these changes in the energy sector for the rest of the California economy are needed for planning and policy formulation.

The objectives of this study, performed under sponsorship of the California Energy Resources Conservation and Development Commission (CERCDC) are to 1) describe quantitatively the California energy industry and its relationship to the California and U.S. economies, 2) provide the analytic capability for determining the direct and indirect employment and income impacts resulting from a given energy future for California, and 3) demonstrate and test the methodology with scenarios that embody varying combinations of conventional energy technologies, new energy technologies and energy conserving measures.

In order to quantify the employment and income impacts of future energy systems we have developed and linked an energy supply model for California and an input-output (I-O) model of the California economy. The energy supply model simulates the construction and operation of energy resource extraction, transportation, and conversion facilities for the period 1975 to 1995. It calculates the capital and operating requirements, including materials and fuel, for these energy facilities. The indirect manpower and income effects are then estimated by transforming these requirements into inputs for the input-output model. This I-O model represents the economy as a matrix of purchases and sales among all producing and consuming sectors. The interdependence among sectors is explicitly accounted for, so that the impact of changes in the production of any given sector can be traced to all other sectors.

For comparative impact analysis we developed three scenarios of future energy growth in California. These scenarios are not forecasts; rather they were chosen to demonstrate the use of our methodology.

The first scenario is based on California electric utility plans and published projections of oil and gas supply and demand. The second scenario, developed in consultation with the CERCDC staff, differs from the first by 1) reducing natural gas consumption, 2) assuming no additional construction of nuclear generating capacity beyond that currently under construction, 3) accelerating the contribution from new energy technologies, including the solar-thermal heating of buildings, and 4) emphasizing the contribution from geothermal resources. Essentially, this scenario calls for a change in the level of energy demand and a change in the mix of energy supply sources.

The third scenario was developed from the first, with the intent of investigating the impact of implementing three energy conservation programs. These programs are 1) the delamping of fluorescent lighting fixtures in commercial buildings, 2) the building of "solar tempered" or "passive solar" housing for all new residential construction, and 3) the retrofitting of existing housing with insulation.

This report is divided into three major sections with supporting appendices.

Section II describes the character of the present California energy system, including time series for in-state petroleum and natural gas production, and generation and sales of electricity. Employment, income and wage rates for the California energy industry have also been tabulated and compared to the national average.

Section III contains a description of the input details necessary for each scenario, along with a display of the resource requirements resulting from each scenario. These results are then compared in order to point out the major differences in direct and indirect impacts.

Section IV discusses the three energy conservation programs as alternatives to investments in energy supply facilities. In this section each conservation program is examined individually in order to isolate some of the specific tradeoffs involved in its implementation.

A detailed description of both the energy supply model for California and the California I-O model is given in Appendix A. In Appendices B, C,

and D we discuss the three conservation measures and display the capital and manpower requirements and estimated energy and capacity savings for each. Appendices E, F and G contain material on wind power, solar thermal-electric power plants and electrical energy conversion from municipal solid wastes, including data on the capital and manpower requirements for each of these new technologies.

II. ECONOMIC PROFILE OF THE CALIFORNIA ENERGY INDUSTRY

For this section we have gathered available data from a variety of sources on the economic sectors comprising the California energy industry. The energy industry in California consists of four major sectors:

1) Oil and Gas Extraction (SIC 13)
2) Petroleum Refining and Related Industries (SIC 29)
3) Electric Utilities (SIC 491)
4) Gas Utilities (SIC 492)

For each of these sectors we present data on the amount of energy produced and sold and its value. We also present data on employment, income and earnings generated by these sectors.

Table 1 shows time series for the production of oil, gas and natural gas liquids in California from 1964 through 1975.[1-3] These data are summarized in Fig. 1. These trends in production of the three major fuels in California show different movements over the decade covered. The production of petroleum rises from 300 million barrels in 1964 to 375 million barrels in 1968, an average annual rate of growth of 5.6 percent. From 1969 through 1975 petroleum production falls at an average annual rate of 3.0 percent to a level of 322 million barrels.

The production of natural gas moves erratically from 1964 through 1968, averaging 683 billion cubic feet per year. Production then declines continuously to the level of 368 billion cubic feet per year in 1974. The average annual rate of decline over the 1968-75 period is 9.4 percent. As for natural gas liquids, production falls in each year with the exception of a small increase in 1966. The average annual rate of decline over the eleven-year interval being 8.5 percent. A comparison of production of these fuels in California to the national production figures shows that for 1975[17] the production of crude petroleum in California is approximately 10.6 percent of the national domestic production (including Alaska) and slightly less than two percent for both natural gas and natural gas liquids.

Table 1

Summary of Annual California Oil and Gas Production

Year	Crude Petroleum[a] Quantity 10^6 bbl	Crude Petroleum[a] Value 10^6 \$[c]	Natural Gas[b] Quantity 10^9 ft^3	Natural Gas[b] Value 10^6 \$[c]	Natural Gas Liq.[a] Quantity 10^6 bbl	Natural Gas Liq.[a] Value 10^6 \$[c]	Total value (all fuels) 10^6 \$
1964	300	729	664	199	25.5	70	998
1965	316	753	644	199	23.7	65	1017
1966	345	813	715	223	24.5	70	1106
1967	359	829	679	202	23.3	66	1097
1968	375	884	713	221	22.0	62	1167
1969	375	920	672	206	21.2	58	1184
1970	372	945	642	206	19.0	58	1205
1971	358	975	602[f]	196	17.8	52	1223
1972	347	943	555[f]	205	14.3	44	1192
1973	336	1045	514[f]	192	12.2	43	1280
1974	323	1748	388[f]	201	11.0	78	2027
1975	322[d]	1940[e]	368[f]	224[e]	10.0[g]	h	>2164

a. Source (except as noted): Ref. 1.

b. Source: Ref. 2. The value was obtained by adjusting the figures given in the California Statistical Abstracts to reflect the more accurate gas production numbers. One important caveat should be noted here. The natural gas production numbers listed here are for "marketed production," which means gross production at the wellhead minus gas used for repressuring the oil/gas field. Some sources, such as the California PUC, show only "net marketed production," which is the gas available to California after the quantities consumed in field use of natural gas (as a fuel), use and losses in transmission, and vented or flared gas are all removed from the "marketed production" figure.

c. Dollar values given in current dollars for the year of interest.

d. Source: Ref. 2, 1975.

e. Source: Ref. 2. These values have been adjusted to include OCS oil and gas.

f. Natural gas production numbers before 1970 do not include production from federal OCS lands off California; for the years 1971 to 1975, federal OCS gas production is included in these totals.

g. Source: Ref. 3.

h. Value of natural gas liquids not available for 1975.

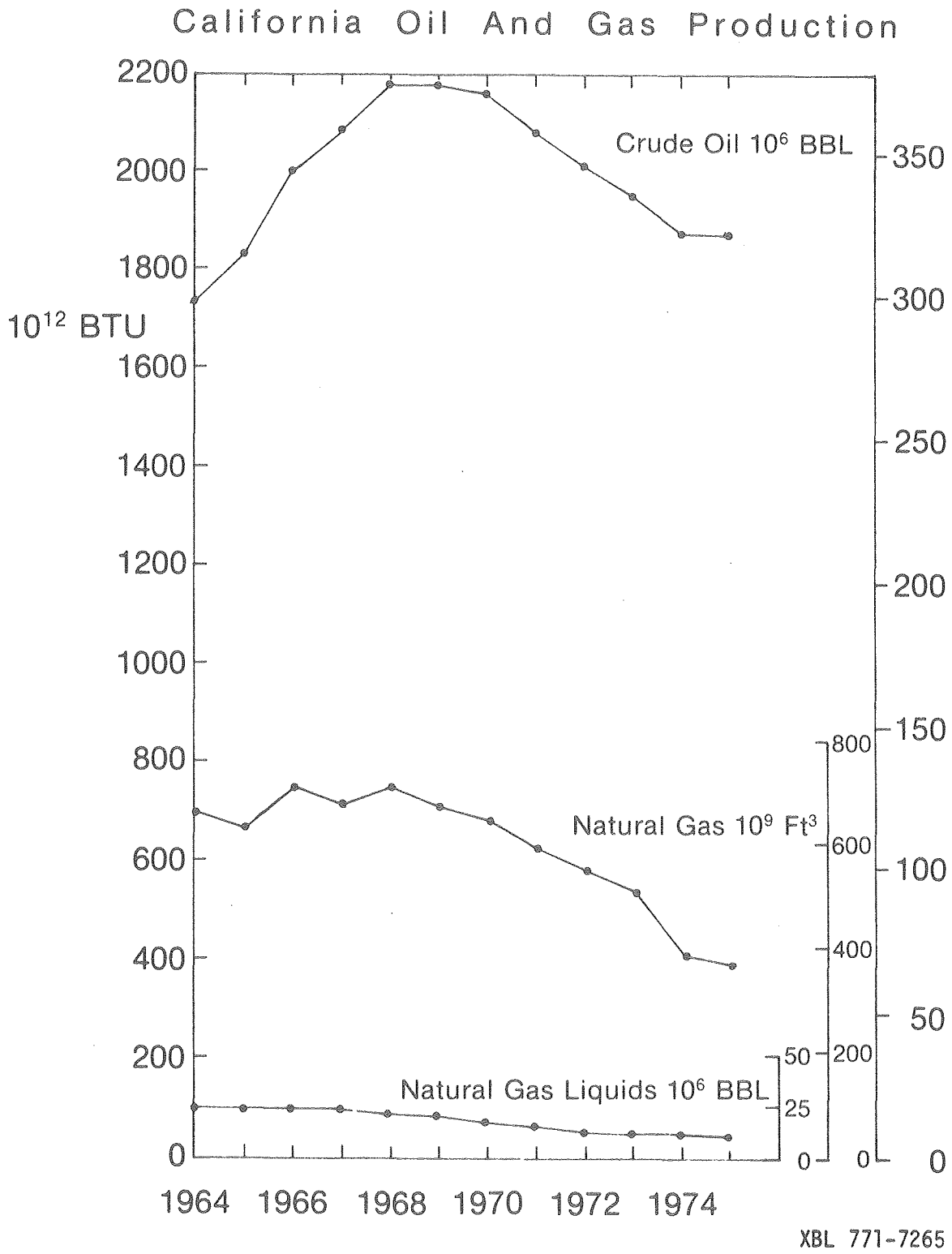

California Oil And Gas Production
Crude Oil 10⁶ BBL
Natural Gas 10⁹ Ft³
Natural Gas Liquids 10⁶ BBL
10¹² BTU
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
350
300
250
200
150
100
50
0
800
600
400
200
0
50
25
0
1964
1966
1968
1970
1972
1974
XBL 771-7265

Figure 1

In Table 2 we present time series showing the trends in production and consumption of electrical energy in California over the years 1964 through 1975.[1,3,4] Consumption of electricity rises continuously through 1973 at an average annual rate of 7.0 percent. In 1974 it falls by 4.4 percent. The production also rises through 1973, with a slight interruption in 1972. The average annual rate of growth here is 5.0 percent. In 1974 production of electrical energy falls by 11.5 percent, then increases again in 1975. These data are shown in Fig. 2. The electrical energy production in California amounts to about seven percent of the national production.

It is apparent from these time series that California has entered a phase of declining production of primary energy. With energy consumption still increasing California must rely more and more on out-of-state energy sources. In fact, California has not been "self sufficient" in terms of supply-demand balances for natural gas and oil since the late 1940's or early 1950's. Figure 2 shows that the state has also become a net importer of electricity. Faced by these trends in energy production and consumption, California must assess the impacts of alternative energy futures. In later sections of this report we examine three alternatives for future California energy supply and demand, but first we describe some economic impacts of the existing energy industry.

Table 3 displays our estimates of value added contributed to California's Gross State Product by four energy sectors for the year 1972. Alongside these estimates we present the contribution of U.S. energy sectors to Gross National Product for the same year. Note that the two energy resource sectors in California contribute relatively more to the Gross State Product that they contribute nationally to Gross National Product. Conversely, the electric and gas utility sectors are relatively smaller within the State as compared to their contribution nationally. In overall terms, however, these energy sectors form the same percentage of total value added both in the state and the national economies.

In Table 4 we present data on employment and earnings in the energy sectors. These figures indicate that California accounts for seven percent of the total U.S. employment in the oil and gas extraction sector. In petroleum refining California accounts for 14 percent of U.S. employment in that sector; in the electric, gas utilities sector the figure is nine

Table 2

Historical Production and Use of Electrical Energy in California[a]
(in 10^9 kwh)

	Generated by Utilities			Sales				
					Commercial + Industrial			
	Private	Public	Total	Residential	Small	Large	Other[b]	Total
1964	67.0	20.2	87.2 (87.2)	21.0	22.9	30.1	3.3	77.3 (79.7)
1965	69.5	23.5	93.0 (93.1)	23.0	27.1	29.7	3.3	83.1 (85.4)
1966	77.8	24.2	102.0 (102.0)	25.4	33.7	30.0	5.6	94.7 (94.8)
1967	79.6	28.9	108.5 (108.5)	27.8	34.5	31.7	6.3	100.4 (100.5)
1968	87.1	27.4	114.5 (114.5)	29.5	37.6	34.6	6.6	108.3 (108.3)
1969	84.8	33.5	118.3 (118.3)	32.5	38.6	36.8	7.4	115.3 (115.3)
1970	87.2	34.9	122.1 (122.1)	34.6	41.3	39.1	8.1	123.1 (123.0)
1971	87.9	34.7	122.6 (125.4)	37.8	43.4	40.8	8.2	130.2 (125.8)
1972	93.5	31.8	125.3 (123.1)	39.8	46.8	44.1	8.9	139.6 (134.9)
1973	99.1	38.0	137.1 (134.3)	42.2	47.9	46.2	9.1	145.4 (140.1)
1974	85.1	36.2	121.3 (114.1)	41.4	44.7	43.7	9.2	139.0 (135.6)
1975	90.2	35.1	125.3 (137.1)	43.4	46.7	42.7	10.6	143.4 (145.4)

a. Reference 4. The numbers in parentheses are from Ref. 1 except for 1975, which are from Ref. 3. These parenthetical values are shown to illustrate the fact that different sources do not agree. We do not understand the differences, except to note that in the case of electricity generated in 1975, the main difference appears to be that the CERCDC number includes electricity generated by coal-fired power plants located out-of-state, but partially owned by California utilities. The FPC number, on the other hand, apparently counts only electricity generated within the state. The difference between sales and generation includes both imported power, and transmission line losses.

b. Includes street lighting, public agencies and railroads.

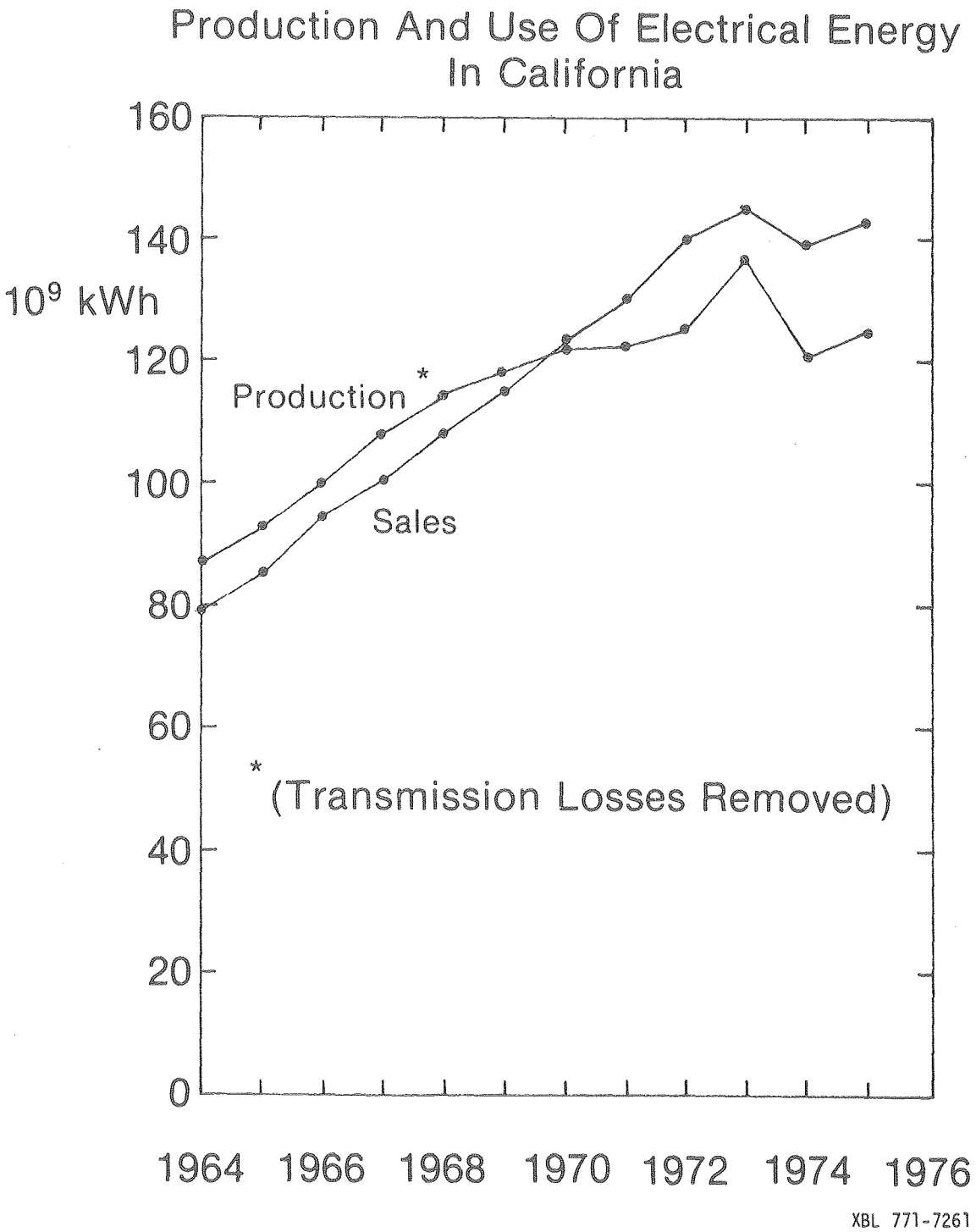

Production And Use Of Electrical Energy
In California
160
140
120
100
80
60
40
20
0
10^9 kWh
Production *
Sales
* (Transmission Losses Removed)
1964
1966
1968
1970
1972
1974
1976
XBL 771-7261

Figure 2

Table 3

Estimated Value Added 1972 10^6 Dollars

Industry	SIC	California	Percent of Gross State Product	United States	Percent of Gross National Product
Crude Petroleum & Natural Gas	1311; 1321	1,432.9	1.14	8,723.4	0.74
Refined Petroleum	2810; 2990	718.9	0.57	5,664.9	0.48
Electric Utilities	4910; 4932	1,451.9	1.16	18,053.6	1.54
Gas Utilities	4920; 4932	825.6	0.66	8,648.0	0.74
Total		4,429.3	3.53	41,089.9	3.50

Source: Ref. 5.

Table 4

Employment and Earnings in Energy Sectors, California and U.S., 1972 and 1974

Industry	Year	California[a]			National[b]		
		Employment	Average Hourly Earnings ($)	Average Weekly Hours	Employment	Average Hourly Earnings ($)	Average Weekly Hours
Oil & Gas Extraction	1972	20,000	5.23	40.4	268,200	4.00	43.0
	1974	21,800	6.25	39.9	304,500	4.82	44.6
Petroleum Refining	1972	22,700	5.21	41.2	152,300	5.25	41.8
	1974	22,400	6.00	41.2	154,800	5.96	42.1
Electric, Gas & Sanitary Services	1972	63,500	5.70	40.5	712,900	4.83	41.5
	1974	65,600	6.41	40.9	742,100	5.49	41.3

a. Bulletin #1370 U.S.Department of Labor, Bureau of Labor Statistics, Employment and Earnings Statistics for States and Areas.

b. Bulletin #1312-10, U.S.Department of Labor, Bureau of Labor Statistics, Employment and Earnings U.S., 1909-1975.

0 0 0 1 7 0 5 0 2 8

percent. Average hourly earnings run slightly higher for California workers in these sectors, while the average work week is slightly shorter.

Table 5 sets out data on wages and employment for detailed (4-digit SIC) energy sectors in California based on first quarter 1975 returns. The annual payroll estimates are based on first quarter figures. In terms of employment, the petroleum refining and utilities sectors comprise the bulk of California employment in the energy sectors.

In considering the impacts of the energy industry on the state's economy, it is important to note that these sectors are among the least labor intensive. Using 1972 data,[5,6] we have ranked the 368 sectors of the national economy in order of decreasing employment per million dollars of gross output. Of the four energy sectors in California, Electric Utilities was the highest with a rank of 301 (14.3 employees per million dollars), whereas Petroleum Refining was the lowest with a rank of 353 (4.7 employees per million dollars). The median value of all sectors was 27.5 employees per million dollars. When ranked by employment per million dollars of value added, all four sectors were in the lowest five percentile. In terms of energy policy, this means that large changes in output in those sectors are required before there will be significant changes in employment.

Table 5

Wages and Employment in California Energy Industries, 1975, I Quarter

	1972 SIC Code	Industry	No. of Firms	Annual Payroll Based on First Quarter 1975 Wages	Average First Quarter Employment
1	1310	Crude Petroleum & Natural Gas	314	194.9	11511
2	1320	Natural Gas Liquids	6	1.2	81
3	1380	Oil and Gas Field Services	406	160.4	10834
Sub Tot.	13	Oil and Gas Extraction	726	356.5	22426
4	2910	Petroleum Refining	99	442.4	23472
5	4910	Electric Utilities	26	220.3	14718
6	4920	Gas Utilities	18	133.7	9307
7	4930	Combination Utilities	77	495.4	33900
Sub Tot.	Part. 49	Total Gas & Electric Utilities	121	849.4	57925

Source: California Department of Employment Development data; processed by LBL Employment Information Systems Project.

III. ANALYSIS OF SCENARIOS

SCENARIO DESCRIPTION

Three scenarios were analyzed to examine a range of alternative energy futures for California. These scenarios were constructed not as forecasts but to demonstrate the use of the methodology developed at LBL. The results, which were calculated using the models described in Appendix A, include the direct and indirect economic impacts of constructing and operating energy and associated transportation facilities during the period 1976 to 1990.

The first scenario is based on projected power plant construction schedules provided by the electric utilities to CERCDC and on estimates of natural gas and crude oil supply and demand.[7-9] It was constructed jointly by the staffs of the Energy Analysis Program at LBL and CERCDC. The second scenario postulates lower natural gas availability than in the first scenario. It also includes extensive deployment of advanced electricity production technologies. These are wind turbine generators, solar thermal-electric power plants and waste-fired electricity generation. A large block of nuclear power generation in the first scenario is replaced by geothermal and advanced technologies in the second scenario. This scenario also includes active solar heating units. It was formulated by the CERCDC staff.

The third scenario emphasizes three conservation activities: delamping in commercial buildings, passive solar houses, and retrofit insulation of residences. These activities affect the growth in consumption of peak and base electrical power and natural gas. The third scenario was constructed from the first scenario by reducing the demand for electricity and natural gas.

INPUT DATA

The input to each scenario includes estimates of future supply and demand of fuels and electricity. The required data are listed in Table 6. The demand estimates specify the quantities of natural gas, oil or electricity. Supply estimates specify the source and quantity of natural gas, the quantities of onshore and offshore oil and the characteristics of all fuels and power plants.

Natural gas demand specification is broken down into firm and interruptible demand categories. Oil demand is specified by four major categories: transportation, industry non-fuel, residential and commercial and industry fuel. The latter two categories are satisfied by excess gas supply as a first priority, if it is available. Oil needed for electricity generation is computed by the model based on the type of electric generating capacity and its operating characteristics.

Three types of electrical power plants that use petroleum are included in our analysis: oil-fired power plants, gas turbine power plants and combined cycle power plants. Other types of power plants include coal-fired plants, nuclear reactors, hydroelectric plants, pumped storage and geothermal facilities. The electricity supply system is specified by the operating characteristics and the generating capacity of each type of power plant. The model then converts these figures into the type and quantity of fuel supply required. In addition to these conventional power plants we have included wind turbine generators, solar thermal-electric power plants and biomass-fired power plants. Data on these plants are of a tentative nature since none of these plants have been used commercially on a large scale. More detail on the data is included in Appendices E, F, and G.

The three conservation activities considered in the third scenario are: retrofit insulation, delamping in commercial buildings and passive solar housing. Cost and manpower data on these activities have been acquired from several sources and are presented in Appendices B, C, and D. Potential demand for these activities has also been estimated.

Natural gas supply to California is specified by its source and quantity. Oil supplies are categorized as California onshore, California offshore and overseas. Coal and uranium supplies are assumed to be

Table 6

Inputs to a California Energy Demand Scenario (1976-1995)

I. Annual Gas Demand (10^{12} ft^3/year)

1. Firm
2. Interruptible

II. Annual Oil Demand (10^6 barrels/year)

1. Transportation
2. Industry non-fuel
3. Residential and commercial
4. Industry fuel

{ Satisfied by gas if available; excess demand filled by oil.

III. Annual Schedule of Electric Power Plant Capacities by Region (MWe)

1. Oil-fired
2. Coal-fired with sulfur removal facilities
3. Gas turbine
4. Combined cycle
5. Nuclear reactor (LWR)
6. Hydroelectric
7. Pumped storage
8. Geothermal

IV. Annual Schedule of Non-Conventional Facilities

1. Retrofit insulation
2. Delamping in commercial buildings
3. Solar heating and cooling
4. Waste-fired power plant
5. Solar thermal power plant
6. Wind-fired electricity generation

available from out-of-state sources. Characteristics of all these fuels as well as the corresponding power plants are specified. Detailed specifications of the data and supply assumptions are included in Appendix A.

Fuel Supply

The quantity of energy consumed by each source in the three scenarios is listed in Table 7. The second and third scenarios call for a lower rate of growth of energy consumption, 2.0 percent and 2.4 percent versus 2.6 percent in the first scenario. Oil supplies in the three scenarios show little variation (less than 10 percent) over the twenty-year span from 1975 to 1995. Gas supplies on the other hand drop by 55 percent, and 12 percent by 1995 in the second and third scenarios from a supply of 1.4×10^{15} BTU in the first scenario. The reduction in the third scenario is due to retrofit insulation and passive solar housing programs.

Electricity forms the third major form of energy supply to California. The second and third scenarios postulate about 4.1×10^{15} BTU of fuel used for electricity generation by 1995 which is slightly less than the 4.3×10^{15} BTU required in the first scenario. The composition of the electricity supply in the second scenario is, however, very different from that in the first and third scenarios. As can be seen from Table 7, advanced electricity production technologies and active solar heating form a major source of energy supply in the second scenario. The energy consumption data are also plotted in Figs. 3, 4, and 5.

Gas Demand and Supply

The annual firm and interruptible gas demand forecast from 1976 to 1985 for the first scenario was obtained from the California Public Utilities Commission[7] and is shown in Table 8. Using a linear extrapolation procedure this demand forecast was extended to 1995. Gas supply sources and quantities were obtained from the FEA study of the California Nuclear

Table 7

Primary Energy Sources for California
(10^{12} BTU)

	1975	1980	1985	1990	1995
Scenario 1					
Natural Gas	1952	1481	1818	1314	1263
Coal (SNG)[f]	0	0	258	258	258
Oil[a]	3347	4170	3840	4396	4570
Electricity[b]	1245	1766	2443	3449	4322
Oil[c]	873	1034	1085	939	691
Coal[c]	93	136	297	329	382
Hydro[d]	138	150	121	178	222
Geothermal[c]	75	176	296	326	517
Nuclear[c]	66	270	581	1677	2502
Adv. Tech.[e]	0	0	3	5	8
Solar Heating	0	0	0	0	0
Total	5671	6383	7274	8483	9722
Scenario 2					
Natural Gas	1952	1402	929	781	633
Coal (SNG)[f]	0	0	0	0	0
Oil[a]	3346	3804	4182	4146	4101
Electricity[b]	1245	1964	2635	3389	4146
Oil[c]	873	1045	1192	927	695
Coal[c]	93	223	350	507	634
Hydro[d]	138	151	164	184	205
Geothermal[c]	75	269	463	1188	1913
Nuclear[c]	66	266	406	409	412
Adv.Tech.[e]	0	10	60	174	287
Solar Heating	0	85	170	237	307
Total	5671	6210	6724	7626	8492

Table 7 (Continued)

	1975	1980	1985	1990	1995
Scenario 3					
Natural Gas	1952	1386	1813	1308	1240
Coal (SNG)[f]	0	0	0	0	0
Oil[a]	3347	4074	3885	4424	4564
Electricity[b]	1245	1670	2265	3268	4115
Oil[c]	873	938	1116	958	687
Coal[c]	93	136	248	284	341
Hydro[d]	138	150	165	162	206
Geothermal[c]	75	176	296	326	517
Nuclear[c]	66	270	437	1533	2356
Adv.Tech.[e]	0	0	3	5	8
Solar Heating	0	0	0	0	0
Total	5671	6192	6847	8042	9232

a. This category includes oil used for electricity generation, and does not include exports from California.

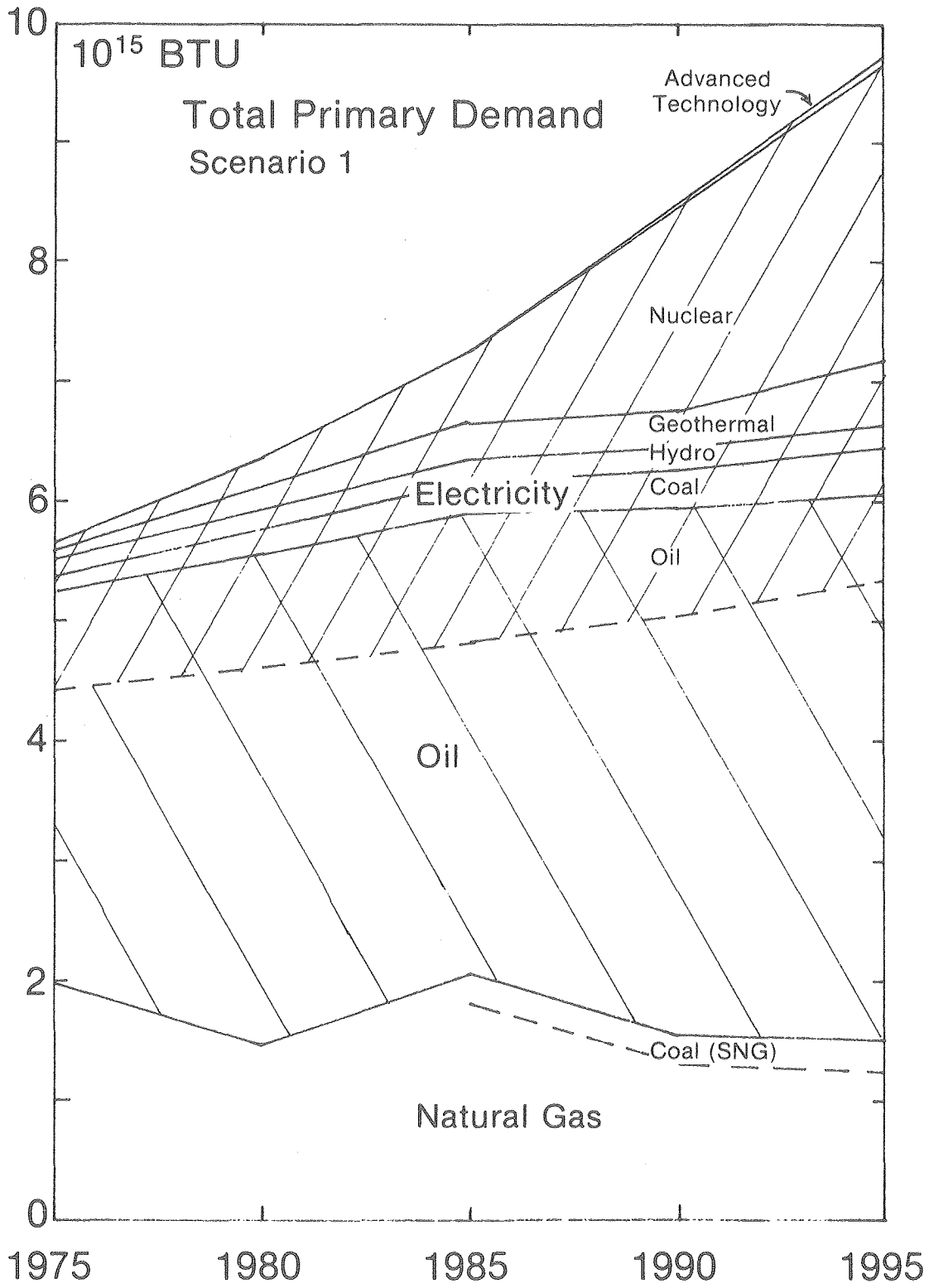
b. Total fuel used for electricity generation, includes oil.

c. Input fuel quantities (in BTU) which account for thermal efficiencies.

d. Output energy (in BTU).

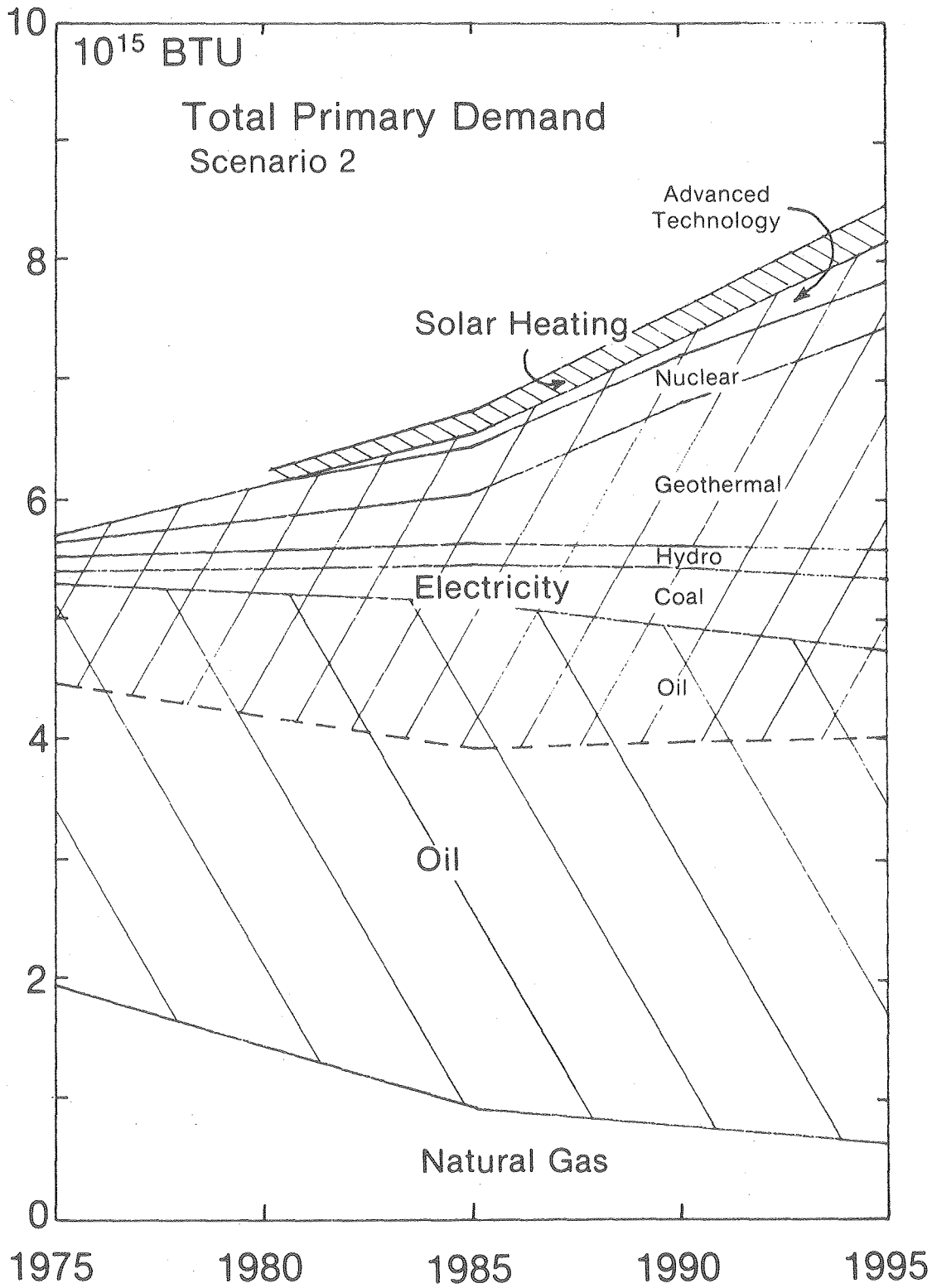
e. Includes biomass, accounted as input (fuel) energy, and wind, solar electric and fuel cells accounted as output energy.

f. Input energy. The efficiency for conversion to high BTU gas is about 55 percent.



XBL 771-7264

Figure 3



XBL 771-7263

Figure 4

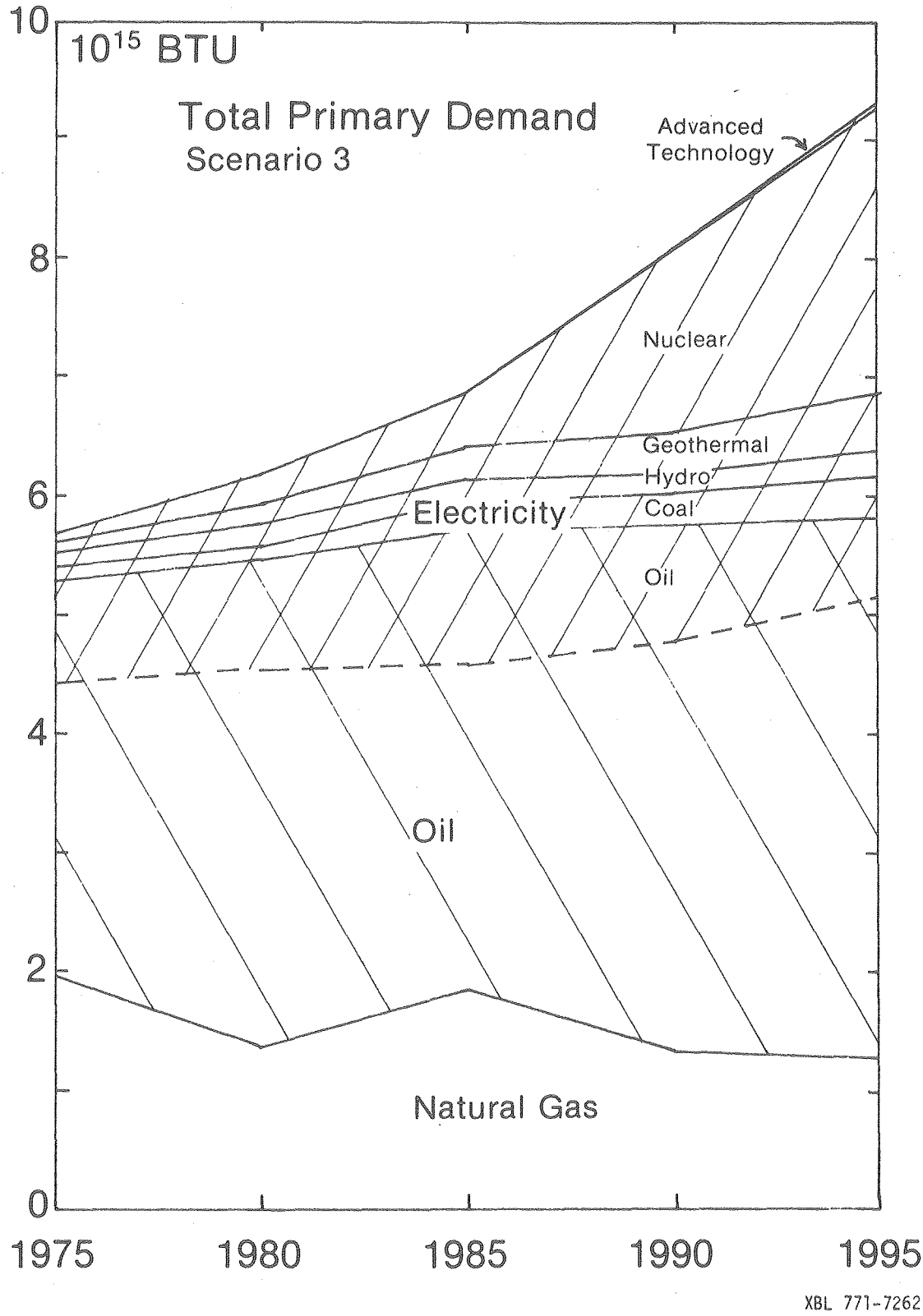

10
8
6
4
2
0
10^{15} BTU
Total Primary Demand
Scenario 3
Advanced
Technology
Nuclear
Geothermal
Hydro
Coal
Electricity
Oil
Oil
Natural Gas
1975
1980
1985
1990
1995
XBL 771-7262

Figure 5

Table 8

Schedule of Gas Supply and Demand
(10^9 ft^3/yr)

	1975	1980	1985	1990	1995
Scenario 1					
Demand					
Firm[a]	957[b]	983	1030	1080[c]	1120[c]
Interruptible[d]	736	715	694	673	652
Industrial fuel[e]	236	197	112	124	236
Res.+ Comm.[e]	23	23	17	17	17
Field use & losses[e]	160[b]	170	200	200	160
Total Demand	2112	2088	2053	2094	2185
Supply[f]					
California	361[g]	349	317	250	250
Federal OCS	6[g]	6	100	200	200
Alaska	0	0	365	365	365
Southwestern	1159[b]	789	601	0	0
SNG(S.W.)	0	0	141	141	141
Canada	365[b]	183	183	50	0
Other LNG	0	108	191	404	404
Total Supply	1891	1435	1898	1410	1360
Unsatisfied Demand	221	653	155	681	829
Scenario 2[h]					
Demand					
Firm	957[b]	826[i]	700	577[i]	453
Interruptible	736[b]	368[i]	0	0	0
Industrial fuel	236	590[i]	944	925[i]	905
Res.+ Comm.	23	23[i]	23	98[i]	174
Field use & losses	160[b]	170	200	200	160
Total Demand	2112	1980	1867	1800	1692
Supply					
California	361[g]	360[i]	358	313[i]	267
Federal OCS	6[g]	16[i]	27	114[i]	200
Alaska	0	0	73	110[i]	146
Southwestern	1159[b]	709[i]	259	130[i]	0
SNG(S.W.)	0	0	0	0	0
Canada	365[b]	274[i]	183	91[i]	0
Other LNG	0	0	0	0	0
Total Supply	1891	1359	900	758	613
Unsatisfied Demand	221	619	967	1042	1079

Table 8 (Continued)

	1975	1980	1985	1990	1995
Scenario 3[j]					
Demand					
Firm	957	891	903	937	962
Interruptible	736	715	694	673	652
Industrial fuel	236	197	112	124	236
Res.+ Comm.	23	23	17	17	17
Field use & losses	160	170	200	200	160
Total Demand	2112	1996	1926	1951	2027
Supply					
California	361	349	317	250	250
Federal OCS	6	6	100	200	200
Alaska	0	0	365	365	365
Southwestern	1159	789	601	0	0
SNG(S.W.)	0	0	0	0	0
Canada	365	183	183	50	0
Other LNG	0	16	191	402	387
Total Supply	1891	1343	1757	1267	1202
Unsatisfied Demand	221	653	169	683	825

a. Reference 7.

b. Actual 1975 value from Ref. 3.

c. Extrapolated.

d. We have used the 1975 value from Ref. 3. The California PUC has estimated that the interruptible gas demand will remain constant for the next decade. We have used this estimate for the 1995 demand, and have interpolated for the years between 1975 and 1995.

e. Reference 8, medium production, medium use case.

f. Reference 9, Table 2C.3-3.

g. Reference 2.

h. Supply-demand value for scenario 2 received from CERCDC, except as noted.

i. Interpolated.

j. Supply-demand values for scenario 3 are based upon scenario 1, with the conservation impacts allocated as follows: the gas savings are assumed to be firm demand, hence this demand requirement is reduced; on the supply side, we assume that no Southwestern SNG development will occur, and that remaining gas savings will reduce the need for "Other LNG" gas.

Power Plants Initiative.[9] Annual gas supply was estimated by linear interpolation of the data for each source. The gas supply estimates are also shown in Table 8.

For the second scenario the gas demand and supply information was supplied by CERCDC. By 1995 California "imports" gas only from Alaska while the southwestern and Canadian sources are phased out. Gas consumption in the third scenario grows at a slower rate due to the conservation programs. This reduced demand for gas results in cancellation or delayed implementation of some supply sources. We have decided to first reduce the synthetic gas supply and then reduce imported LNG from the levels specified in the first scenario.

Oil Demand and Supply

For the first and third scenarios, forecasts of oil demand for each of the four subcategories (transportation, residential and commercial, industry fuel and industry non-fuel) for 1980, 1985, 1990 and 1995 were obtained from the Rand Corporation[8] and are displayed in Table 9. These oil demand forecasts reflect the medium production, medium use case defined in that report. Estimates of crude oil supply sources and quantities are also shown in Table 9. The additional oil requirement is "imported." Oil demand and supply forecasts for the second scenario were obtained from the CERCDC staff.

Power Plants

The annual schedule of electric power plant capacities by region (either in- or out-of-state) was obtained from the utility submissions to the CERCDC. This schedule is shown in Table 10 and was included in the first scenario. A similar schedule for the second scenario was developed from the data supplied by the CERCDC. These data are for the three years 1975, 1985, and 1995. Figures for the intervening years were calculated by linear interpolation. In this scenario all coal power

Table 9

Schedule of Crude Oil Supply and Demand
(10^6 bbl/yr)

	1975	1980	1985	1990	1995
Scenario 1					
Demand					
Unsatisfied gas[a]	39	116	28	121	148
Electric gen.[b]					
residual	136	154	154	118	79
distillate	3	11	20	33	33
Transportation[c]	360	391	406	425	469
Industry non-fuel[c]	58	67	77	88	94
Crude oil export[d]	68	68	68	68	68
Total Demand (as crude)[e]	645	787	730	826	856
Supply					
California[f]					
onshore	307[g]	275	249	225	203
offshore	15[g]	103	250	370	350
Total Supply	322	378	499	595	553
Imports Required	323	409	231	231	303
Scenario 2					
Demand					
Unsatisfied gas[a]	39	110[i]	172	186[i]	192
Electric gen.[b]					
residual	136	157[i]	169	121[i]	80
distillate	3	10[i]	22	29[i]	33
Transportation[h]	360	318[i]	275	290[i]	305
Industry non-fuel[h]	58	75[i]	92	105[i]	118
Crude oil export[h]	68	68[i]	68	68[i]	68
Total demand (as crude)[e]	645	724	789	783	775
Supply					
California[h]					
onshore	307[g]	271[i]	234	182[i]	129
offshore	15[g]	84[i]	153	153[i]	153
Total Supply	322	355	387	335	282
Imports Required	323	369	402	448	493

Table 9 (Continued)

	1975	1980	1985	1990	1995
Scenario 3[j]					
Demand					
Unsatisfied gas	39	116	30	122	147
Electric gen.[b]					
residual	136	140	162	126	84
distillate	3	9	16	29	27
Transportation	360	391	406	425	469
Industry non-fuel	58	67	77	88	94
Crude oil export	68	68	68	68	68
Total Demand (as crude)	645	770	738	831	855
Supply					
California					
onshore	307	275	249	225	203
offshore	15	103	250	370	350
Total Supply	322	378	499	595	553
Imports Required	323	392	239	236	302

a. Taken from Table 8, converted into barrels of middle distillate.

b. Values calculated from the assumed electrical generation capacity mix and capacity factors used as inputs to the California Energy Supply Model.

c. Reference 8, medium production, medium use case.

d. Taken to be constant at the level of exports for 1975, Ref. 3.

e. Calculated as crude oil; numbers in demand categories will not sum to this due to different heat contents of various oil products.

f. Based on projections in Ref. 8, and Ref. 12.

g. Values for 1975 taken from Ref. 2.

h. Supply-demand values for scenario 2 received from CERCDC, except as noted.

i. Interpolated.

j. Supply-demand values for scenario 3 are based upon scenario 1, with the conservation impacts shown as changes in oil demand for electrical energy generation.

CERCDC FIRST SCENARIO
GENERATING CAPACITY
BY TYPE OF POWER PLANT

YEAR	HYDRO (IN STATE)	PUMPED STORAGE	OIL	COMBINED CYCLE	GAS TURBINE	COAL IN	COAL OUT	NUCLEAR IN	NUCLEAR OUT	GEO-THERMAL	WIND	FUEL CELL	SOLAR THERMAL	CAPACITY AVAILABLE
SUM 1975	7385(1193)	1055	21361	24	1083		5252(2276)	1379		502				36258
1976	-11	192			323		750 (157)	1060						37979
1977		193	-42	600	162			1068						39960
1978		385	-21	236	166			80		271				41077
1979			707	236	114			70		165				42369
1980	31				466					240		26		43132
SUM 1980	7405(1193)	1825	22005	1096	2314		6002(2433)	3657		1178		26		43132
1981	201	1120	-137	360	600			220		110				45606
1982	270				75			1100	1270 (190)	220				47462
1983	364		-157		375	800	1000 (575)	880		140		52		50491
1984	150		-273		675		1000 (575)	950	1270 (190)	220		42		53020
1985	90		-186		300		750 (450)	1100		110		104		54988
SUM 1985	8480(1193)	2945	21252	1456	4339	800	8752(4033)	7907	2540 (381)	1978		224		54988
1986			-352	1290	-900		750 (450)	3350	1270 (190)	100		156		59273
1987	140(-331)			234	101			1300			33			60750
1988			-271	468	505			4750			33			66235
1989			-90					2250			34			68429
1990			-422			520		3650		100				72277
SUM 1990	8620 (862)	2945	20117	3448	4045	1320	9502(4483)	23207	3810 (571)	2178	100	380		72277
1991					202	520		1250		150				74399
1992			-448		402			3350						77703
1993			-351		253	520		1250		150			100	79625
1994			-334		53	520		3350						83214
1995	640	2400	-1354	-24	1255			2250		980			100	89461
SUM 1995	9260 (862)	5345	17630	3424	6210	2880	9502(4483)	34657	3810 (571)	3458	100	380	200	89461

NUMBER IN BRACKETS REPRESENTS CALIFORNIA SHARE OF OUT OF STATE CAPACITY

Table 10

plants were assumed to be located outside California. Table 11 shows the power plant schedule for this scenario.

In scenario 3 two nuclear power plants and one coal-fired power plant that would come on line after 1983 need not be constructed due to the reduced base load power demand resulting from the delamping program. Furthermore, passive solar housing and retrofit insulation reduces the need for gas turbine and pumped storage peaking units. These measures also reduce the growth in demand for natural gas. Since power plants under construction would not be cancelled we decided to let the oil-fired plants (mostly older units) operate at a reduced load factor until 1983 to match the reduced demand for electricity. The power plant capacity schedule for the third scenario is presented in Table 12.

Solar Heating

Active solar heating units were included only in the second scenario. The data provided by CERCDC included the energy that would be available from these units by 1985 and by 1995 as shown in Table 7. The capital and manpower requirements for these units are taken from Ref. 10.

Non-electrical Facilities

Given the fuel supply and demand data and the mix of electrical generating facilities, the model creates a schedule for constructing and operating the facilities needed to supply the required energy. These include coal and uranium mines, oil wells, refineries, and oil and gas import facilities. The major non-electrical energy facilities that are included in each scenario are summarized in Table 13. In addition, there are fuel transportation and electricity transmission and distribution facilities.

The manpower and capital required to construct and operate all the energy and transportation facilities included in the model are presented in Table A-1 (in Appendix A). Also included are the nominal sizes of each type of facility.

CERCDC SECOND SCENERIO
GENERATING CAPACITY
BY TYPE OF POWER PLANT

YEAR	HYDRO (IN STATE)	PUMPED STORAGE	OIL	COMBINED CYCLE	GAS TURBINE	COAL IN	COAL OUT	NUCLEAR IN	NUCLEAR OUT	GEO-THERMAL	WIND	BIOMASS	SOLAR THERMAL	CAPACITY AVAILABLE
SUM 1975	8700	1000	21391	24	1085		2300	1400		500				36400
1976	-20	190	195	158	368		340	440		260				38331
1977	-20	190	195	158	368		340	440		260				40262
1978	-20	190	195	158	368		340	440		260				42193
1979	-20	190	195	158	368		340	440		260				44124
1980	-20	190	195	158	368		340	440		260		180		46235
SUM 1980	8600	1950	22366	814	2925		4000	3600		1800		180		46235
1981	-20	190	195	158	368		340	440		260		180		48346
1982	-20	190	195	158	368		340	440		260		180		50457
1983	-20	190	195	158	368		340	440		260		180		52568
1984	-20	190	195	158	368		340	440		260		180		54679
1985	-20	190	195	158	368		340	440		260	10	200	10	56830
SUM 1985	8500	2900	23341	1604	4765		5700	5800		3100	10	1100	10	56830
1986	50	240	-564	186	147		650			970	419	180	649	59757
1987	50	240	-564	186	147		650			970	419	180	649	62684
1988	50	240	-564	186	147		650			970	419	180	649	65611
1989	50	240	-564	186	147		650			970	419	180	649	68538
1990	50	240	-564	186	147		650			970	419	180	649	71465
SUM 1990	8750	4100	20521	2534	5500		8950	5800		7950	2105	2000	3255	71465
1991	50	240	-564	186	147		650			970	419	180	649	74392
1992	50	240	-564	186	147		650			970	419	180	649	77319
1993	50	240	-564	186	147		650			970	419	180	649	80246
1994	50	240	-564	186	147		650			970	419	180	649	83173
1995	50	240	-564	186	147		650			970	419	180	649	86100
SUM 1995	9000	5300	17701	3464	6235		12200	5800		12800	4200	2900	6500	86100

Table 11

CERCDC THIRD SCENARIO
GENERATING CAPACITY
BY TYPE OF POWER PLANT

YEAR	HYDRO (IN STATE)	PUMPED STORAGE	OIL	COMBINED CYCLE	GAS TURBINE	COAL IN	COAL OUT	NUCLEAR IN	NUCLEAR OUT	GEO-THERMAL	WIND	FUEL CELL	SOLAR THERMAL	CAPACITY AVAILABLE
SUM 1975	7385(1193)	1055	21361	24	1083		5252(2276)	1379		502				36258
1976	-11	192			323		750 (157)	1060						37979
1977		193	-42	600				1068						39798
1978		385	-21	236				80		271				40749
1979			707	236				70		165				41927
1980	31									240		26		42224
SUM 1980	7405(1193)	1825	22005	1096	1406		6002(2433)	3657		1178		26		42224
1981	201		-137	360	600			220		110				43578
1982	270				75			1100	1270 (190)	220				45434
1983	364		-157		375		1000 (575)	880		140		52		47663
1984	150		-273				1000 (575)		1270 (190)	220		42		48567
1985	90		-186		300		750 (450)			110		104		49435
SUM 1985	8480(1193)	1825	21252	1456	2756		8752(4033)	5857	2540 (381)	1978		224		49435
1986			-352	1290	-900		750 (450)	3350	1270 (190)	100		156		53720
1987	140(-331)			234				1300			33			55096
1988			-271	468				4750			33			60076
1989			-90					2250			34			62270
1990			-422			520		3650		100				66118
SUM 1990	8620 (862)	1825	20117	3448	1856	520	9502(4483)	21157	3810 (571)	2178	100	380		66118
1991						520		1250		150				68038
1992			-448					3350						70940
1993			-351			520		1250		150			100	72609
1994			-334		-16	520		3350						76129
1995	640	2400	-1354	-24	271			2250		980			100	81392
SUM 1995	9260 (862)	4225	17630	3424	2111	2080	9502(4483)	32607	3810 (571)	3458	100	380	200	81392

NUMBER IN BRACKETS REPRESENTS CALIFORNIA SHARE OF OUT OF STATE CAPACITY

Table 12

Table 13

Major Non-electrical Energy Facilities

	1975	1980	1985	1990	1995
Scenario 1					
Coal strip mine[a] ($6X10^6$ ST/yr)	0.7	1.0	3.9	4.1	4.4
U strip mine[a] ($4.4X10^5$ ST/yr ore)	1.4	2.4	4.8	11.8	15.4
Coal Gasification (Hi BTU ($80X10^9$ ft^3/yr)	0	0	1.7	1.7	1.7
Refinery ($2X10^5$ bbl/day)	9.8	11.9	11.1	12.5	13.0
Oil import facility ($1X10^6$ bbl/day)	0.8	1.2	0.7	0.7	0.9
LNG import facility ($2.8X10^9$ ft^3/day)	0	0	0.6	0.8	0.8
Scenario 2					
Coal strip mine[a] ($6X10^6$ ST/yr)	0.7	1.4	2.4	3.4	4.4
U strip mine[a] ($4.4X10^5$ ST/yr ore)	1.0	2.2	2.8	.28	2.8
Refinery ($2X10^5$ bbl/day)	10.0	10.7	11.7	12.1	12.4
Oil import facility ($1X10^6$ bbl/day)	0.9	0.9	1.1	1.3	1.5
LNG import facility ($2.8X10^9$ ft^3/day)	0	0	0	0	0

Table 13 (Continued)

	1975	1980	1985	1990	1995
Scenario 3					
Coal strip mine[a] ($6X10^6$ ST/yr)	0.7	1.0	1.7	2.0	2.4
U strip mine[a] ($4.4X10^5$ ST/yr ore)	1.4	2.4	3.8	10.9	14.5
Refinery ($2X10^5$ bbl/day)	9.8	11.7	11.2	12.6	13.0
Oil import facility ($1X10^6$ bbl/day)	0.8	1.1	0.7	0.7	0.9
LNG import facility ($2.8X10^9$ ft^3/day)	0	0	0.6	0.8	0.8

a. California share of out-of-state facilities.

RESULTS

In this section we discuss the resource requirements called for by each scenario. The resources requirements are aggregated into two regions: California and the Southern Mountain Region.* Since the input data are in most instances specified at five- and ten-year intervals, the results, although calculated on a yearly basis, have also been aggregated into five-year periods. Results are presented for three five-year intervals running from 1976 through 1990. Requirements for the period 1991 through 1995 have not been calculated, since estimates for these years would have required us to specify facilities coming on line after 1995, the final year included in our scenarios. Capital and operating costs are expressed in constant 1974 dollars.**

Construction Requirements

Over a long period, one would expect that increased amounts of energy supplied would be accompanied by increased commitments of resources to energy facilities. However, because many of the energy facilities are constructed in large discrete units, and are typically built ahead of demand, the growth in construction requirements may, over a short period such as fifteen years, move irregularly when compared to the actual growth of energy consumption. In scenarios 1 and 3 for example, the resource requirements reach a peak during the 1981-85 period and then decrease during the next period, while in the second scenario they decrease steadily over the fifteen-year period. This irregular growth can be attributed to the following major facets of our accounting of the energy supply system for California.

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*The Southern Mountain Region comprises the states of Arizona, Colorado, Nevada, New Mexico and Utah.

**It should be noted that the construction resources data include resources required for engineering, design, procurement, construction and startup for each energy facility. There are other costs, mainly "owners' costs" which are highly variable and difficult to estimate. These are not included in our results. Owners' costs typically include project feasibility studies, site evaluation, studies required for site and project approval by government agencies, interest during construction, and land costs. Owners' costs average 25 to 30 percent of construction costs incurred by the builders for many major energy facilities. They are higher for energy extraction facilities, on the order of 40 to 60 percent.

Capital outlays for construction of synthetic natural gas (SNG) plants, LNG import facilities and offshore oil wells account for $5 billion of the $22.5 billion of capital invested in the first scenario during 1981-85. In this scenario, SNG plants are not constructed after 1985, LNG import facilities constructed during 1981-85 are sufficiently large to accommodate all LNG imports until 1995, and construction outlays for offshore oil wells decline by almost 50 percent during 1986-90 as offshore oil supply is not projected to increase as rapidly. These facilities account for a $3.4 billion decrease between the latter two periods. Reduced construction of several other facilities accounts for the remaining decrease of $4 billion.

The decrease is misleading for two reasons. First, we do not account for the capital needed to extract natural gas and oil from Alaska and foreign countries for use in California. Capital for extracting oil would have to be expended during the first quinquenium. Alaskan LNG supplies level off by 1985 so this would add to the resource requirements during the second quinquenium. Other LNG supplies would require capital mainly during the 1976-80 and 1986-90 periods with some requirements during 1981-85.

Second, the electricity supply schedule submitted by the utilities to CERCDC calls for 5200 MWe of electrical capacity added during 1995 excluding the nuclear and coal-fired capacity scheduled for that year. Capital expenditure for these plants would take place entirely during 1991-95. Much of the expenditure for the nuclear and coal-fired plants also occurs during this period. The reasons presented above for the temporal distribution of resource inputs should serve as a caution to the reader that the time trends of our results must not be extrapolated in any simple manner.

Tables 14 and 15 display the capital and manpower resources required for the construction of the various facilities in the three scenarios. The requirements are broken down to show facilities actually constructed within California and the share of out-of-state facilities which would serve California's energy demand. For example, if it is estimated that California would use 50 percent of the power produced by an out-of-state facility, then it is assumed that 50 percent of the capital required for such a facility would be forthcoming from California utilities. Although the manpower requirements have been broken down

Table 14

Construction Capital Requirements
(10^6 1974 dollars)

	1976-80	1981-85	1986-90	Total 1976-90	Avg. Annual Capital Cost
Scenario 1					
Energy Facilities	6196	14358	8628	29182	1945
Transport. Facilities	3935	8186	6611	18732	1249
TOTAL	10131	22544	15239	47914	3194
Scenario 2					
Energy Facilities	14908	13941	13918	42767	2851
Transport. Facilities	4143	3771	4223	12137	809
TOTAL	19051	17712	18141	54904	3660
Scenario 3					
Energy Facilities	5491	11813	8756	26060	1737
Transport. Facilities	3175	6470	6341	15986	1066
Conservation Programs	757	0	0	757	50
TOTAL	9423	18283	15097	42803	2853

Table 15

Manpower Requirements for Construction
(Man-Years)

	1976-80	1981-85	1986-90	Total 1976-90	Avg. Man-Year Per Year
Scenario 1					
Energy Facilities	56,200	113,900	96,200	266,300	17,750
Transport.Facilities	45,700	89,500	81,700	216,900	14,460
TOTAL	101,900	203,400	177,900	483,200	32,210
Scenario 2					
Energy Facilities	209,000	180.800	161,700	551,500	36,770
Transport.Facilities	49,500	43,400	46,300	139,200	9,280
TOTAL	258,500	224,200	208,000	690,700	46,050
Scenario 3					
Energy Facilities	49,100	101,000	98,500	248,600	16,570
Transport.Facilities	37,700	71,800	78,500	188,000	12,530
Conservation Programs	8,000	0	0	8,000	530
TOTAL	94,800	172,800	177,000	444,600	29,640

according to the same proportions, the out-of-state figures here have no meaning in terms of employment generated within California; hence these are not included in the tables.

Scenario 1 would require investment capital of $47.9 billion (1974 dollars) over the fifteen-year period ending in 1990, $29.1 billion dollars for energy facilities plus $18.7 billion for transportation facilities. Scenario 2, which calls for extensive investment in solar space heating equipment, calls for total capital investment of $54.9 billion (1974 dollars) by 1990, $42.7 billion in energy facilities plus $12.1 billion in transportation facilities.

Although the capital requirements of scenario 2 are 15 percent higher than scenario 1, the manpower requirements within California are some 43 percent higher (691 thousand man-years versus 483 thousand). This is accounted for primarily by the heavy emphasis on the construction and installation of solar space heating equipment, a relatively labor intensive activity as compared to the construction of conventional energy facilities.

Scenario 3, which incorporates the three major conservation programs described briefly above, and in detail in Appendices B, C, and D, requires total investment capital of $42.8 billion (1974 dollars) through 1990, $26 billion for energy facility construction, $15.9 billion for transportation facilities, plus $0.8 billion for conservation activities. This represents a reduction of 11 percent in capital requirements when compared to scenario 1. Since manpower requirements are reduced by approximately eight percent in scenario 3 (445 thousand man-years as against 483 thousand), it appears that the relative capital intensity of scenario 3 is higher than scenario 1.

Looking at the time phasing of capital expenditures shown in Tables 16 to 18, we find that in scenario 1 capital outlays more than double between the first and second five-year interval, and then fall by 32 percent in the third. In scenario 2 the flow of capital remains at a uniformly high level over the fifteen-year period. In scenario 3 the pattern is similar to that of scenario 1, capital requirements rising by 94 percent and then falling by 17 percent.

CERCDC SCENARIO 1 - CONSTRUCTION REQUIREMENT

ENERGY FACILITIES

SOUTHERN MOUNTAIN	CAPITAL REQUIREMENT (10^6 1974 $)			MAN-POWER REQUIREMENT (man-years)		
	76-80	81-85	86-90	76-80	81-85	86-90
25 SURFACE WESTERN COAL MINE (6 MMT/Y)	0	90.	0	0	837.	0
27 COAL GASIFICATION - HIGH BTU (250 MMCF/D)	0	1500.	0	0	21563.	0
33 SURFACE URANIUM MINE (1200 TONS/D ORE)	25.	70.	81.	465.	1365.	1589.
35 URANIUM MILL (1000 T/D ORE)	12.	29.	31.	193.	474.	497.
49 COAL FIRED POWER PLANT-LOW BTU (800 MWE)	103.	482.	0	1097.	5595.	0
53 SULFUR OXIDE REMOVAL (800 MWE)	4.	180.	0	67.	2324.	0
59 LIGHT WATER REACTOR (LWR) (1100 MWE)	152.	117.	0	1895.	1763.	0
	297.	2468.	111.	3717.	33921.	2087.

CALIFORNIA	CAPITAL REQUIREMENT			MAN-POWER REQUIREMENT		
	76-80	81-85	86-90	76-80	81-85	86-90
2 OFFSHORE OIL PRODUCTION-LOWER 48 (4 MB/D)	2008.	3992.	1651.	9419.	18616.	7689.
5 LOW-GASOLINE REFINERY (200 MB/D)	451.	623.	236.	7527.	9595.	4103.
11 ONSHORE OIL IMPORT (1000 MB/D)	37.	0	0	359.	0	0
17 OFFSHORE GAS PRODUCTION-LOWER 48 (50 MMCF/D)	109.	408.	231.	587.	2250.	1288.
21 LNG IMPORT (2795 MMCF/D)	0	420.	0	0	5182.	0
38 LWR FUEL FABRICATION-NO PU RECYCLE(600MTU/Y)	37.	11.	37.	543.	167.	543.
47 OIL-FIRED POWER PLANT (800 MWE)	142.	0	0	1877.	0	0
49 COAL FIRED POWER PLANT-LOW BTU (800 MWE)	138.	130.	567.	1572.	1444.	6435.
53 SULFUR OXIDE REMOVAL (800 MWE)	10.	70.	160.	167.	875.	2083.
55 WIND TURBINE GENERATOR (4 MWE)	0	0	50.	0	0	220.
56 COMBINED CYCLE POWER PLANT (400 MWE)	156.	273.	57.	1690.	2791.	646.
57 GAS TURBINE POWER PLANT (133 MWE)	187.	187.	106.	1283.	1283.	727.
58 FUEL CELLS (26 MWE)	8.	111.	0	20.	281.	0
59 LIGHT WATER REACTOR (LWR) (1100 MWE)	1573.	5065.	5092.	20792.	66059.	69696.
61 SOLAR POWER PLANT (100MWE)	0	0	26.	0	0	139.
62 DAM + HYDROELECTRIC POWER PLANT (200 MWE)	269.	271.	22.	4326.	4054.	381.
63 PUMPED STORAGE (1000 MWE)	251.	0	108.	3768.	0	1511.
64 GEOTHERMAL POWER COMPLEX (200 MWE)	522.	330.	174.	2270.	1343.	777.
	5899.	11890.	8517.	56201.	113941.	96240.

Table 16

CERCDC SCENARIO 1 - CONSTRUCTION REQUIREMENT

TRANSPORTATION FACILITIES

SOUTHERN MOUNTAIN		CAPITAL REQUIREMENT (10^6 1974 $)			MAN-POWER REQUIREMENT (man-years)		
		76-80	81-85	86-90	76-80	81-85	86-90
9	RAILROAD (40 MILES, SINGLE TRACK)	99.	679.	270.	1254.	8241.	3331.
15	COAL TRUCK (25 T)	3.	1.	1.	0	0	0
20	230 KVAC TRANSMISSION LINE (480 MWE, 500 MI)	1.	6.	0	15.	74.	0
22	500 KVAC TRANSMISSION LINE (2080 MWE, 500 MI)	0	7.	0	0	83.	0
26	CONVENTIONAL RAIL (10,500 TON)	99.	368.	160.	0	0	0
		202.	1060.	431.	1270.	8399.	3331.

CALIFORNIA		CAPITAL REQUIREMENT			MAN-POWER REQUIREMENT		
		76-80	81-85	86-90	76-80	81-85	86-90
3	OIL TANKER (90,000 DWT)	160.	0	32.	0	0	0
5	OIL TANK TRUCK (9500 GAL)	51.	28.	44.	0	0	0
6	PRODUCTS PIPELINE (70 MB/D, 100 MI)	44.	16.	31.	450.	165.	329.
7	HOT OIL PIPELINE (40 MB/D, 50 MI)	51.	13.	0	442.	110.	0
8	REFINED PRODUCTS BULK STATION (69 MB/D)	59.	14.	48.	536.	125.	437.
9	RAILROAD (40 MILES, SINGLE TRACK)	1.	29.	30.	37.	332.	378.
10	COAL TRAIN (10,500 TON)	0	18.	9.	0	0	0
17	GAS DISTRIBUTION FACILITIES (50 MMSCF/D)	71.	166.	85.	902.	2171.	1207.
19	LNG TANKER (2.6 BCF)	100.	600.	200.	0	0	0
20	230 KVAC TRANSMISSION LINE (480 MWE, 500 MI)	121.	242.	95.	1650.	3185.	1266.
21	345 KVAC TRANSMISSION LINE (960 MWE, 500 MI)	0	120.	0	0	1695.	0
22	500 KVAC TRANSMISSION LINE (2080 MWE, 500 MI)	188.	359.	188.	2372.	4531.	2372.
25	ELECTRICITY DISTRIBUTION (131.6 MWE)	28 8.	5521.	5418.	39321.	77136.	75751.
		3733.	7126.	6180.	45710.	89451.	81741.

Table 16 (Continued)

CERCDC SCENARIO 2 - CONSTRUCTION REQUIREMENT

ENERGY FACILITIES

		(10^6 1974 $) CAPITAL REQUIREMENT			(man-years) MAN-POWER REQUIREMENT		
SOUTHERN MOUNTAIN		76-80	81-85	86-90	76-80	81-85	86-90
25	SURFACE WESTERN COAL MINE (6 MMT/Y)	44.	44.	44.	414.	414.	414.
33	SURFACE URANIUM MINE (1200 TONS/D ORE)	14.	6.	0	277.	150.	0
35	URANIUM MILL (1000 T/D ORE)	7.	0	7.	113.	0	113.
49	COAL FIRED POWER PLANT-LOW BTU (800 MWE)	528.	788.	1040.	5984.	9023.	11875.
53	SULFUR OXIDE REMOVAL (800 MWE)	160.	207.	320.	2083.	2688.	4167.
		753.	1046.	1411.	8871.	12274.	16568.

		CAPITAL REQUIREMENT			MAN-POWER REQUIREMENT		
CALIFORNIA		76-80	81-85	86-90	76-80	81-85	86-90
2	OFFSHORE OIL PRODUCTION-LOWER 48 (4 MB/D)	1664.	1136.	0	7773.	5299.	0
5	LOW-GASOLINE REFINERY (200 MB/D)	486.	0	0	7988.	0	0
11	ONSHORE OIL IMPORT (1000 MB/D)	58.	37.	0	626.	359.	0
17	OFFSHORE GAS PRODUCTION-LOWER 48 (50 MMCF/D)	33.	143.	340.	165.	797.	1875.
38	LWR FUEL FABRICATION-NO PU RECYCLE(600MTU/Y)	0	48.	0	0	711.	0
47	OIL-FIRED POWER PLANT (800 MWE)	180.	175.	0	2292.	2258.	0
55	WIND TURBINE GENERATOR (4 MWE)	0	216.	1046.	0	951.	4603.
56	COMBINED CYCLE POWER PLANT (400 MWE)	132.	151.	160.	1375.	1561.	1682.
57	GAS TURBINE POWER PLANT (133 MWE)	238.	200.	102.	1633.	1373.	700.
59	LIGHT WATER REACTOR (LWR) (1100 MWE)	828.	87.	0	11291.	1572.	0
62	DAM + HYDROELECTRIC POWER PLANT (200 MWE)	0	81.	86.	0	1264.	1389.
63	PUMPED STORAGE (1000 MWE)	225.	232.	287.	3349.	3474.	4272.
64	GEOTHERMAL POWER COMPLEX (200 MWE)	761.	1746.	2880.	3295.	7802.	12400.
65	SOLAR SPACE HEATING (30000 DWELLINGS)	9550.	8642.	7606.	169241.	153341.	134825.
		14155.	12895.	12507.	209027.	180763.	161746.

Table 17

CERCDC SCENARIO 2 - CONSTRUCTION REQUIREMENT

TRANSPORTATION FACILITIES

SOUTHERN MOUNTAIN	(10^6 1974 $) CAPITAL REQUIREMENT			(man-years) MAN-POWER REQUIREMENT		
	76-80	81-85	86-90	76-80	81-85	86-90
9 RAILROAD (40 MILES, SINGLE TRACK)	141.	197.	278.	1701.	2434.	3434.
15 COAL TRUCK (25 T)	2.	1.	1.	0	0	0
20 230 KVAC TRANSMISSION LINE (480 MWE, 500 MI)	0	0	0	0	0	0
22 500 KVAC TRANSMISSION LINE (2080 MWE, 500 MI)	17.	0	17.	214.	0	214.
26 CONVENTIONAL RAIL (10,500 TON)	212.	230.	345.	0	0	0
	371.	428.	641.	1914.	2434.	3648.

CALIFORNIA	CAPITAL REQUIREMENT			MAN-POWER REQUIREMENT		
	76-80	81-85	86-90	76-80	81-85	86-90
3 OIL TANKER (90,000 DWT)	96.	64.	64.	0	0	0
5 OIL TANK TRUCK (9500 GAL)	40.	39.	32.	0	0	0
6 PRODUCTS PIPELINE (70 MB/D, 100 MI)	28.	31.	16.	286.	329.	165.
7 HOT OIL PIPELINE (40 MB/D, 50 MI)	53.	36.	0	471.	302.	0
8 REFINED PRODUCTS BULK STATION (69 MB/D)	41.	34.	34.	375.	312.	312.
17 GAS DISTRIBUTION FACILITIES (50 MMSCF/D)	60.	113.	150.	801.	1445.	1979.
19 LNG TANKER (2.6 BCF)	0	100.	100.	0	0	0
20 230 KVAC TRANSMISSION LINE (480 MWE, 500 MI)	95.	29.	162.	1266.	423.	2109.
22 500 KVAC TRANSMISSION LINE (2080 MWE, 500 MI)	359.	0	359.	4531.	0	4531.
25 ELECTRICITY DISTRIBUTION (131.6 MWE)	2999.	2897.	2665.	41799.	40601.	37240.
	3772.	3343.	3582.	49529.	43411.	46336.

Table 17 (Continued)

CERCDC SCENARIO 3 - CONSTRUCTION REQUIREMENT

ENERGY FACILITIES

SOUTHERN MOUNTAIN	CAPITAL REQUIREMENT (10^6 1974 $)			MAN-POWER REQUIREMENT (man-years)		
	76-80	81-85	86-90	76-80	81-85	85-90
25 SURFACE WESTERN COAL MINE (6 MMT/Y)	0	20.	22.	0	191.	206.
33 SURFACE URANIUM MINE (1200 TONS/D ORE)	0	61.	80.	0	1167.	1571.
35 URANIUM MILL (1000 T/D ORE)	0	22.	32.	0	360.	520.
49 COAL FIRED POWER PLANT-LOW BTU (800 MWE)	103.	482.	0	1097.	5595.	0
53 SULFUR OXIDE REMOVAL (800 MWE)	4.	180.	0	67.	2324.	0
59 LIGHT WATER REACTOR (LWR) (1100 MWE)	152.	117.	0	1895.	1763.	0
	260.	883.	134.	3059.	11400.	2298.

CALIFORNIA	CAPITAL REQUIREMENT			MAN-POWER REQUIREMENT		
	76-80	81-85	86-90	76-80	81-85	86-90
2 OFFSHORE OIL PRODUCTION-LOWER 48 (4 MB/D)	2008.	3992.	1651.	9419.	18616.	7689.
5 LOW-GASOLINE REFINERY (200 MB/D)	667.	374.	486.	10952.	5710.	7988.
11 ONSHORE OIL IMPORT (1000 MB/D)	37.	0	0	359.	0	0
17 OFFSHORE GAS PRODUCTION-LOWER 48 (50 MMCF/D)	109.	408.	231.	587.	2250.	1288.
21 LNG IMPORT (2795 MMCF/D)	0	420.	0	0	5182.	0
38 LWR FUEL FABRICATION-NO PU RECYCLE(600MTU/Y)	37.	11.	11.	543.	167.	105.
47 OIL-FIRED POWER PLANT (800 MWE)	142.	0	0	1877.	0	0
49 COAL FIRED POWER PLANT-LOW BTU (800 MWE)	0	8.	567.	0	47.	6435.
53 SULFUR OXIDE REMOVAL (800 MWE)	0	0	160.	0	0	2083.
55 WIND TURBINE GENERATOR (4 MWE)	0	0	50.	0	0	220.
56 COMBINED CYCLE POWER PLANT (400 MWE)	156.	273.	57.	1690.	2791.	646.
57 GAS TURBINE POWER PLANT (133 MWE)	70.	100.	0	480.	687.	0
58 FUEL CELLS (26 MWE)	8.	111.	0	20.	281.	0
59 LIGHT WATER REACTOR (LWR) (1100 MWE)	1173.	4632.	5115.	16007.	59841.	69787.
61 SOLAR POWER PLANT (100MWE)	0	0	26.	0	0	139.
62 DAM + HYDROELECTRIC POWER PLANT (200 MWE)	269.	271.	22.	4326.	4054.	381.
63 PUMPED STORAGE (1000 MWE)	34.	0	72.	585.	0	1008.
64 GEOTHERMAL POWER COMPLEX (200 MWE)	522.	330.	174.	2270.	1343.	777.
	5231.	10930.	8622.	49116.	100969.	98549.

Table 18

CERCDC SCENARIO 3 - CONSTRUCTION REQUIREMENT

TRANSPORTATION FACILITIES

SOUTHERN MOUNTAIN		CAPITAL REQUIREMENT (10^6 1974 $)			MAN-POWER REQUIREMENT (man-years)		
		76-80	81-85	86-90	76-80	81-85	86-90
9	RAILROAD (40 MILES, SINGLE TRACK)	96.	318.	273.	1186.	3861.	3377.
15	COAL TRUCK (25 T)	3.	1.	1.	0	0	0
20	230 KVAC TRANSMISSION LINE (480 MWE, 500 MI)	1.	6.	0	15.	74.	0
22	500 KVAC TRANSMISSION LINE (2080 MWE, 500 MI)	0	7.	0	0	83.	0
26	CONVENTIONAL RAIL (10,500 TON)	99.	165.	117.	0	0	0
		199.	497.	391.	1202.	4019.	3377.

CALIFORNIA		CAPITAL REQUIREMENT			MAN-POWER REQUIREMENT		
		76-80	81-85	86-90	76-80	81-85	86-90
3	OIL TANKER (90,000 DWT)	128.	0	32.	0	0	0
5	OIL TANK TRUCK (9500 GAL)	51.	25.	47.	0	0	0
6	PRODUCTS PIPELINE (70 MB/D, 100 MI)	44.	3.	44.	450.	43.	450.
7	HOT OIL PIPELINE (40 MB/D, 50 MI)	15.	61.	0	140.	522.	0
8	REFINED PRODUCTS BULK STATION (69 MB/D)	52.	16.	52.	473.	152.	473.
9	RAILROAD (40 MILES, SINGLE TRACK)	0	0	32.	0	0	403.
10	COAL TRAIN (10,500 TON)	0	0	9.	0	0	0
17	GAS DISTRIBUTION FACILITIES (50 MMSCF/D)	71.	166.	85.	902.	2171.	1207.
19	LNG TANKER (2.6 BCF)	0	700.	200.	0	0	0
20	230 KVAC TRANSMISSION LINE (480 MWE, 500 MI)	244.	213.	95.	3338.	2762.	1266.
21	345 KVAC TRANSMISSION LINE (960 MWE, 500 MI)	0	0	120.	0	0	1695.
22	500 KVAC TRANSMISSION LINE (2080 MWE, 500 MI)	56.	303.	188.	800.	3732.	2372.
25	ELECTRICITY DISTRIBUTION (131.6 MWE)	2315.	4485.	5045.	31612.	62414.	70607.
		2976.	5973.	5950.	37715.	71796.	78474.

Table 13 (Continued)

The rise in capital requirements during the 1981-85 interval in scenario 1 can be traced to heavy outlays on:

1) out-of-state facilities, particularly coal gasification plants, coal-fired power plants and natural gas production facilities
2) increased offshore oil and gas production
3) nuclear facilities
4) LNG import facilities
5) railroad facilities

Investment in each of these facility types, with the exception of nuclear power plants, then falls during the subsequent five-year period (see Table 16). Specifically the sharp drop in capital outlays during 1985-90 is due to diminished expenditures for offshore oil production facilities since offshore oil production is expected to peak by 1990, and in smaller outlays for coal-related facilities including no outlays for construction of coal gasification plants during this period.

The relatively uniform flow of capital requirements over time in scenario 2 masks certain shifts in the components which comprise the totals (see Table 17). Those facility types which call for diminishing investment outlays over the fifteen-year interval are:

1) offshore oil production
2) petroleum refining
3) oil-fired generating capacity
4) gas turbine generating capacity
5) nuclear-fired generating capacity

The facility types which absorb larger amounts of capital over succeeding five-year intervals are:

1) offshore gas production
2) wind-turbine generating capacity
3) geothermal generating capacity

The capital requirements of scenario 2 are dominated by the construction and installation of solar space heating equipment. These requirements amount to 60 percent of total capital required for the scenario.

The time pattern of construction outlays under scenario 3 is similar to scenario 1 (see Table 18). The "lumping" of capital requirements during the second five-year interval is attributable, in general, to the

same list of facilities cited above for scenario 1. Scenario 3 comes in with lower capital requirements largely due to the

1) omission of out-of-state coal gasification
2) reduction in the need for new electricity distribution facilities, and
3) omission of in-state coal-fired and nuclear facilities.

Operation Requirements

Tables 19 and 20 display resources required to operate the energy and transportation facilities called for by the three scenarios. These operations resource figures are not comprehensive. They include only the direct manpower, materials, and equipment required to operate the facilities which are on-line. Central management and staff activities are excluded, as are the costs of fuel inputs. Fuel requirements for the scenarios are discussed above. The data presented here are not designed to establish the full operating costs for the energy-related facilities, but rather to compare the more readily predictable costs of operation of the alternative energy system configurations.

Table 19 indicates that scenarios 1 and 3 are very similar in their operating resource requirements, each requiring an average annual cost in 1974 dollars of approximately $1.6 billion. Scenario 2 comes in higher by approximately 16 percent, or an average annual difference of $250 million. This is largely due to the inclusion in scenario 2 of a large number of solar heating units.

In terms of operating manpower requirements scenarios 1 and 3 again are similar in their requirements. Scenario 1 calls for average annual operating manpower of 55,620 workers as against 54,450 workers for scenario 3. Scenario 2 requires 20,000 additional workers, which is 36 percent higher than scenario 1.

Since these figures for operating requirements do not include major items involved in operation (fuel and labor costs) it is not possible to make statements about the relative labor intensities of the operations phase of the alternative scenarios. We can note that the average annual employment generated by both construction and operation in each scenario run as follows:

Table 19

Partial Operating Costs
(10^6 1974 $)

	1976-80	1981-85	1986-90	Total 1976-90	Avg. Cost Per Year
Scenario 1					
Energy Facilities	5,668	6,360	7,277	19,305	1,288
Transport.Facilities	1,405	1,546	1,839	4,790	319
TOTAL	7,073	7,906	9,116	24,095	1,607
Scenario 2					
Energy Facilities	6,162	8,072	9,469	23,703	1,580
Transport.Facilities	1,308	1,394	1,493	4,195	280
TOTAL	7,470	9,466	10,962	27,898	1,860
Scenario 3					
Energy Facilities	5,566	6,146	7,046	18,758	1,251
Transport.Facilities	1,382	1,470	1,717	4,569	304
TOTAL	6,948	7,616	8,763	23,327	1,555

Table 20

Manpower Requirements for Operation
(Man-Years)

	1976-80	1981-85	1986-90	Total 1976-90	Avg.Man-year Per Year
Scenario 1					
Energy Facilities	150,500	155,400	163,900	469,800	31,320
Transport.Facilities	109,300	119,100	136,100	364,500	24,300
TOTAL	259,800	274,500	300,000	834,300	55,620
Scenario 2					
Energy Facilities	194,400	271,400	331,800	797,600	53,170
Transport.Facilities	103,900	111,300	118,300	333,500	22,230
TOTAL	298,300	382,700	450,100	1,131,100	75,400
Scenario 3					
Energy Facilities	150,000	153,200	161,200	464,400	30,960
Transport.Facilities	108,300	114,600	129,500	352,400	23,490
TOTAL	258,300	267,800	290,700	816,800	54,450

Scenario 1	88,000 man-years
Scenario 2	121,000 man-years
Scenario 3	84,000 man-years

The difference between the high and low manpower figures here is 37,000 man-years.

Indirect Impacts

To gain a somewhat more complete assessment of the economic impacts of the alternative scenarios, we have linked the direct capital construction requirements derived from the Energy Supply Planning Model to a California Interindustry Model (see Appendix A for details of methodology). By doing this we are able to estimate the indirect impacts of construction expenditures on the various industrial sectors which make up the California economy. Furthermore, we are able to estimate and compare the overall contributions of each scenario to Gross State Product.

Table 21 summarizes the direct and indirect contributions of the three scenarios to Gross State Product. The value added figures shown in this table represent payments to the various factors of production (wages, rent, interest and profits). As such they provide a measure of the economic services rendered by these factors. Gross State Product for any given period represents the sum of services rendered by all factors of production in the economy of the state during that period. Summing the value added figures for each scenario is a way of estimating the contribution of each scenario to the general level of economic activity in the state.*

The estimates in Table 21 indicate the following average annual contributions to Gross State Product (1974 dollars):

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*We should note here that not all of the indirect economic impacts generated by the construction activity in each scenario is confined to the State of California. Some of the additional demand elicited by constructing facilities in California will be met by the importation of products produced elsewhere in the United States. Estimates of the proportion of additional demand in each sector which would be met from California production have been based on proportions observed in the 1972 input-output data.

Table 21

Direct and Indirect Contributions of Construction Activity to California Gross State Product (10^6 1974 $)

	1976-80	1981-85	1986-90	Total 1976-90	Avg. Per Year
Scenario 1					
Direct Value Added	2,760	5,530	4,641	12,931	862
Indirect Value Added	3,533	6,976	5,251	15,760	1,050
TOTAL	6,293	12,506	9,892	28,691	1,912
Scenario 2					
Direct Value Added	6,405	5,745	5,435	17,585	1,172
Indirect Value Added	6,164	5,585	5,651	17,400	1,160
TOTAL	12,569	11,330	11,085	34,984	2,332
Scenario 3					
Direct Value Added	2,289	4,834	4,594	11,717	718
Indirect Value Added	3,039	6,233	5,219	14,491	966
Conservation Programs Total Value Added	709	57	57	823	55
TOTAL	6,037	11,124	9,870	27,031	1,802

Scenario 1	$1.91 billion
Scenario 2	$2.33 billion
Scenario 3	$1.80 billion

While scenarios 1 and 3 come within $110 million of each other, scenario 2 is roughly 21 percent higher. However, the $400 million difference between scenario 2 and scenario 1 must be viewed against a Gross State Product which in 1974 was running at an annual rate of $157 billion. With the continued growth in Gross State Product, we are looking at something less than 0.25 percent as a possible net contribution of scenario 2 construction activity.

It is of some interest to compare the ratios of total (direct plus indirect) value added to direct value added among the scenarios. These ratios are:

Scenario 1	2.22
Scenario 2	1.99
Scenario 3	2.25

The explanation for the low ratio exhibited by scenario 2 lies in the heavy outlays for solar space heating equipment. Such equipment is less capital intensive, and therefore sets off a smaller chain of indirect effects than would be set off by equivalent outlays for the equipment going into a power plant.

Table 22 presents the indirect manpower requirements called for by the construction activity postulated in each of the scenarios. The indirect employment impacts in California of scenarios 1 and 3 differ by only five percent, while scenario 2 would have a ten percent greater impact on indirect employment in California than scenario 1. The differential impact on employment of scenario 2 is much stronger in terms of direct employment requirements (42 percent) than it is in terms of indirect employment. The reason for this, once again, lies in the heavy emphasis in scenario 2 on the construction and installation of solar space heating equipment. The production of such equipment (in contrast to its installation) is relatively less labor intensive than is the production of the equipment and components which comprise conventional energy facilities.

Table 22

Indirect Manpower Requirements
(Man-Years)

	1976-80	1981-85	1986-90	Total	Avg. Annual
Scenario 1	189,000	374,600	282,800	846,410	56,400
Scenario 2	330,700	298,800	302,700	932,200	62,100
Scenario 3	180,600	337,600	284,200	802,400	53,493
Energy & Transport. Facilities	162,600	334,600	281,200	778,400	51,893
Conservation Programs	18,000	3,000	3,000	24,000	1,600

Induced Effects

Each of the three scenarios contributes a different amount to personal income in the state. We have not traced the effects of these differences on the California economy. Any increase in personal income will be spent in part on consumer goods and services, which in turn will induce additional employment and income. To calculate these induced impacts one has to make assumptions about 1) the change in the level of personal income due to a change in output in each sector; 2) the resulting shift in income distribution; and 3) the elasticity of demand for the output of each sector by each income class.

A complete analysis of this problem is beyond the scope of this study. However, based on the assumption that changes in income and consumption are proportional to their current distributions, it has been estimated,[11] that for California in 1972 the induced income and employment represents an additional 80 percent change in direct plus indirect values. We do not use this figure in assessing our results; we present it to show that this "multiplier" effect can magnify the differences between scenarios. For this reason, and because of uncertainties in the data and projections used in discussing our results, we will emphasize their relative rather than their absolute values.

DISCUSSION

In considering the results we have just presented, it is instructive to place the difference among the scenarios in the context of a larger energy and economic picture for California over the next 15 to 20 years.

The cumulative twenty-year fuel requirements for the five major non-renewable resources (including geothermal energy) have been calculated. A comparison of scenarios 1 and 3 shows a net cumulative savings for scenario 3 of 6.0×10^{15} BTU (out of a non-renewable resource requirement for scenario 1 of 147.6×10^{15} BTU), or about a four percent savings. A more detailed look at the components of these savings shows about a six percent savings in overall natural gas consumption or the equivalent of nearly 2×10^{14} ft^3 in that twenty-year time period. If one accounts for SNG savings as coal (input energy), then there will be a 42 percent decrease in coal usage, equal to 140×10^6 short tons of coal. Finally there is a one percent oil savings, or nearly 100×10^6 barrels of crude oil, and an eight percent savings in nuclear fuel requirements, or 3.5×10^6 short tons of uranium ore.

Comparing scenarios 1 and 2, more dramatic changes in the use of non-renewable energy resources are evident. In part this is due to lower overall primary energy flow, and in part because there are major shifts to alternative technologies, including a substitution of geothermal electrical generation for electricity supplied by nuclear fission. Overall, the use of non-renewable resources in scenario 2 is 11 percent less than in scenario 1. The largest portion of this is due to a 66 percent reduction in nuclear fuel requirements (27.7×10^6 tons of uranium ore); a 31 percent change in natural gas (equivalent to $\sim 9 \times 10^{12}$ ft^3); and a five percent drop in crude oil flow (nearly 800×10^6 bbls). Including coal used for SNG, scenario 2 shows a decrease in coal use by five percent, or approximately 17×10^6 short tons. The greater use of geothermal resources in this scenario increases the geothermal requirements by 190 percent over scenario 1.

We now place the variation among scenarios in the context of the California economy. In 1974, personal income in California is estimated to have been $125.4 billion.[13] Over the past quarter century, personal income on the national level has typically been about 0.80 of Gross National

Product. Applying this factor to California personal income yields an estimated 1974 Gross State Product of $157 billion. Gross Private Capital Formation on the national level over the past quarter century has averaged roughly 16 percent of GNP.[14] Assuming this relationship to hold for California, we estimate 1974 capital formation in California to have been approximately $25 billion.

Scenario 2 has the largest capital requirements of our three scenarios: $54.9 billion over the fifteen years from 1976 through 1990. This averages to $3.7 billion (1974 dollars) per year. Capital requirements for the energy industry in this scenario therefore average 14 percent of 1974 outlays for total private capital formation in California. But it is perhaps more pertinent to examine the variation in capital requirements between two scenarios, as this would indicate the impact of following one path rather than another. The difference in total capital requirements for scenarios 1 and 2 amounts to $7.0 billion (1974 dollars). Averaged over 15 years the annual difference comes to approximately $0.5 billion, or 2 percent of the 1974 figure for gross private capital formation in California. This change does increase the new capital requirements for the energy sector by 15 percent.

A similar comparison of scenarios 1 and 3 shows a difference in capital requirements of $5.1 billion (1974 dollars), or an average of $0.3 billion dollars annually. This is 1.4 percent of the 1974 California gross private capital formation. However, this difference reduces the new capital requirements for the energy sector by 11 percent.

These figures indicate the limited significance, as regards overall capital needs, of the choices we have posited. The conservation options used in developing scenario 3 are limited to three measures; a more complete set of conservation measures might show a larger impact on capital requirements. Nevertheless, if capital scarcities should develop at a time when the capital requirements in the energy sector are large, any reduction in these requirements due to energy conservation strategies would be important.

A summary of manpower requirements is given in Table 23. The average number of persons who would be employed per year under the scenarios we have analyzed should be viewed against the total California labor

Table 23

Total Manpower Requirements (Man-years)

	Construction Activities		Construction & Operation		Direct + Indirect	
	Total Persons 1976-1990	Average Per Year	Total Persons 1976-1990	Average Per Year	Total Persons 1976-1990	Average Per Year
Scenario 1	483,200	32,210	1,317,500	87,833	2,163,910	144,260
Scenario 2	690,700	46,050	1,821,800	121,453	2,754,000	183,600
Scenario 3	444,600	29,640	1,261,400	84,093	2,063,800	137,586

force, which was just under 9.5 million in 1975.[15] These figures indicate that direct and indirect manpower requirements, even under scenario 2 would absorb less than two percent of the labor force. More pertinent, the difference in average number of persons per year required in scenarios 1 and 2 amounts to 39,000 (see Table 23). This represents less than 0.5 percent of the 1975 California labor force.

Of course, one might argue that it is more significant to compare the construction manpower requirements with the labor force engaged in construction activities. Employment in the construction sector in California has been averaging just over 300,000 during the past decade.[16] With this as a reference point, the maximum difference in construction employment generated by the alternative scenarios amounts to five percent of average annual employment in construction activities in California.

It is also of interest to compare the incremental manpower requirements associated with scenario 2 with the number of new jobs which the California economy may be called upon to create over the next fifteen years. To illustrate this, we note that over the years 1966 to 1974, non-agricultural employment in the state increased on the average by 210,000 per year.[15] If this figure is typical of the employment growth over the next fifteen years, the average additional 39,000 persons per year absorbed by scenario 2 over scenario 1 would make a considerable contribution toward meeting this growth. While scenario 2 appears to have some positive employment impacts, it also has a lower primary energy requirement than scenario 1. One should note our earlier caveat that the aggregated resource requirements are calculated only to 1990. During the next five-year period some of these employment differences could decrease.

A comparison of scenarios 1 and 3 shows that the average annual employment levels stay very nearly the same, while the energy requirements for scenario 3 are lower. If one compares the savings in new energy demand over this fifteen-year period (that is, the additional energy each scenario requires beyond present levels) with the direct manpower and indirect manpower required for construction in the energy sector, the energy required in scenario 3 drops by nearly 17 percent, while the demand for direct and indirect construction manpower decreases by about six percent.

Placed in the context of whether changes in the energy supply-demand picture have employment impacts, our results indicate that there are alternative paths with both lower energy flows and nearly the same or even greater employment levels. These relative statewide employment impacts should be considered as one of the tradeoffs in setting energy policy. However, other important issues, which we have not investigated in this report, such as environmental degradation, radioactive waste disposal, health and safety effects, future resource availability, and reliability play important roles.

If it is desirable to put idle manpower to work, then this problem should be attacked in terms of which alternative uses of the manpower would yield the greatest benefit to the community. To follow a path of least resistance and expand any one sector such as the energy sector, merely because it can generate additional employment would dwarf the apparent short-term gain through job creation. In sum, the problem of generating employment is one which should be tackled on its own, and not be confused with other significant issues.

IV. IMPACTS OF ALTERNATIVE INVESTMENT STRATEGIES

The future dimensions of the California energy system depend in some degree upon the nature and extent of various energy conservation programs. The energy saving aspect of these conservation measures can contribute directly to the alleviation of pressure on the supply of energy resources. In this section we present some preliminary estimates of 1) the potential savings in energy from selected conservation programs, 2) the amount of electrical generating capacity obviated by the implementation of these conservation programs, and 3) the magnitude of certain economic impacts with and without the implementation of the conservation programs. The full impacts of alternative energy paths go beyond the issues considered here. They involve questions of reliability, risk, health and safety effects,and life styles which are beyond the scope of the study reported here.

Pressures on conventional energy resources can also be alleviated by bringing on line certain "new" or "nonconventional" electricity generating technologies. For selected new technologies we have attempted to derive preliminary estimates of the major economic impacts entailed in incorporating these technologies into California's energy supply system. These data are shown in the appendices.

In advance of actual operating experience reliable estimates of potential energy savings and costs associated with energy conservation measures and new energy technologies are difficult to obtain. Our choice of which measures and technologies to include has therefore been governed in part by data constraints. The estimates must be considered tentative and subject to revision. The analysis should therefore be viewed as an initial effort to examine the magnitude of some of the tradeoffs which may be involved in choosing one path rather than another.

The third scenario analyzed in Chapter III incorporates three conservation programs. The total resource requirements calculated for scenario 3 are the outcome of the interaction of these conservation programs with the energy production and transportation facilities specified to complete the California energy system. The results obtained enable comprehensive comparisons to be made among the three scenarios, two of which do not include the conservation programs.

In this section we examine each conservation program individually in order to isolate some of the specific tradeoffs involved in their implementation.

CONSERVATION PROGRAMS

The three energy conservation programs which we have considered are:

1. construction of "solar tempered," or "passive solar" housing;
2. delamping of fluorescent lighting fixtures in commerical buildings;
3. retrofitting of ceilings in the existing housing stock with insulating materials.

For the first of these measures we consider a program for the building of "solar tempered" or "passive solar" housing. A solar tempered house is one whose orientation, insulation and glazing are designed to take maximum advantage of solar heat gain in winter and to minimize solar heat gain in summer. We have hypothesized a program in which all new construction of single and multifamily residential units meet the requirements of passive solar housing. These requirements are summarized in Appendix B. For delamping we have hypothesized a five-year program in which a portion of fluorescent tubes are replaced by Phantom™ tubes in order to reduce energy consumption for lighting. The details of this delamping program are described in Appendix C. The retrofit insulation program would result in the upgrading of the ceiling insulation to an R-19 standard in approximately 4.5 million residential housing units. Once again, we assume a five-year period for completion of this program. Details are spelled out in Appendix D.

Cost and manpower data for the conservation programs as well as for selected energy facilities are presented in Table 24. In the case of the delamping program we have not regarded as net additional costs the cost of producing and installing Phantom™ tubes. If a delamping program of the scope envisaged were undertaken, it is likely that the costs would be comparable to the costs of producing and installing standard fluorescent tubes. As a first approximation it appears reasonable to regard the production of Phantom™ tubes as a substitute for that of

Table 24

Comparison of Economic Impacts of Alternative Investments

Investment	Construction			Annual Operations		
	Capital Cost (10^6\$ 1974)	Direct Manpower (man-years)	Indirect Manpower (man-years)	Cost (10^6\$ 1974)	Manpower (man-years)	Indirect Value Added (10^6\$ 1974)
Nuclear LWR (1100 MWe)	460	6250	8800	5.8	112	164.5
Coal-fired (800 MWe)	260	2970	5700	3.8	125	104.4
Gas turbines (133 MWe)	17	120	330	0.3	7	6.5
Coal Gasification ($250 \times 10^6 ft^3$/day SNG)	750	10780	17100	7.5	590	310.1
Delamping	0	0	0	0	0	0.0
Retrofit Insulation	756	8000	15000	0	0	300.0
Passive Solar Housing (each 5 years)	0	0	3000	0	0	57.0

standard fluorescent tubes, with no significant additional costs entailed. We also assume that delamping would take place during routine replacement of existing fluorescent tubes, hence would entail no additional cost.

In the case of the retrofit insulation program, we have assumed the insulating material to be fiberglas. Estimates are given for the cost of the insulation, the associated value added (largely wages) and the manpower requirements for installation.

Our figures indicate that a passive solar housing program such as we have assumed would be without net additional capital costs. This is due to the fact that the cost of the additional materials going into the construction of passive solar housing would be offset by a reduction in the sizes, and therefore the costs, of heating and air conditioning units necessary to maintain a given temperature in the dwelling. Although we expect no increase in the direct labor for constructing passive solar houses, the indirect effects of materials purchases would result in a net increase in employment. This stems from the fact that the production of the additional housing materials is more labor intensive than the production of heaters and air conditioners.

The implementation of these conservation programs would, other things remaining constant, result in reduced electricity and natural gas consumption, and consequently in a somewhat smaller future generating capacity than would otherwise be needed. Table 25 presents our estimates of the resulting energy savings and reductions in capacity. We estimate that by 1981 the required base load generating capacity could be reduced by as much as 3080 MWe, and the peak load capacity by as much as 1400 MWe. For each subsequent five-year period the peak load capacity could be reduced by an additional 1400 MWe. This would be accompanied by a fuel savings of 320×10^{12} BTU over the first five years, 1010×10^{12} BTU over the first ten years, and 1800×10^{12} BTU over the first 15 years.

In addition to these savings of fuels in electricity generation, we find that because of better insulation there would be large savings in natural gas for space heating. We estimate that cumulative consumption of natural gas would be reduced by 287×10^{12} BTU between 1977 and 1981, by a total of 900×10^{12} BTU by the end of 1986, and by a total of 1590×10^{12} BTU by the end of 1991.

Table 25

Estimates of Energy Savings and Capacity Reduction

	Cumulative Energy Savings						Cumulative Savings in Generating Capacity (MWe)		
	Natural Gas (10^{12}BTU)			Electricity (10^{9}kwh)					
	to 1981	to 1986	to 1991	to 1981	to 1986	to 1991	to 1981	to 1986	to 1991
Delamping	0	0	0	26.2	78.7	131.3	3080[a]	3080[a]	3080[a]
Retrofit Insulation[c]	248	745	1242	1.1	3.3	5.5	0	0	0
Passive Solar Housing[c]	39	155	349	4.8	19.2	43.1	1400[b]	2800[b]	4200[b]
Total	287	900	1591	32.1	101.2	179.9			

a. Base load.

b. Peak load.

c. These programs, taken together, save natural gas equivalent to the projected output from two synthetic natural gas (SNG) plants (total 141 X 10^{9} ft^{3}/yr).

ENERGY FACILITY ALTERNATIVES

To assess more fully the impact of these conservation measures it is necessary now to examine some of the consequences arising from the reduction in required electricity generating capacity. Table 25 indicates that the estimated savings in base load generating capacity from a delamping program would be 3080 MWe. This is equivalent to two 1100 MWe nuclear facilities at a capital cost of $460 million each and one coal-fired plant at $240 million, for a total of $1.2 billion (1974 dollars).* The construction of nuclear facilities is estimated to take place over a nine-year period, while for a coal-fired facility the period is five years. Accompanying these construction outlays would be construction manpower requirements of 12,500 man-years for the nuclear facilities and 2970 man-years for the coal-fired facility. Indirect manpower requirements would amount to 17,600 man-years for the nuclear plants and 5700 man-years for the coal-fired plant. In their operating phase, the two nuclear plants would require $11.6 million (1974 dollars) annually and 224 man-years. The coal plant would require $3.8 million (1974 dollars) annually and 125 man-years.

Since the delamping program requires no additional cost, omitting the construction of the three power plants would reduce the demand for investment capital by $1.2 billion. This would be accompanied by a reduction in the demand for labor by 39,000 man-years.

As for the passive solar housing program, the potential savings of generating capacity are in peak load capacity. Table 25 shows that this program would eliminate the need for 1400 MWe peak load capacity for each five-year period. (See Appendix B for details of how we arrived at this estimate.)

In order to assess the impact of the implementation of this program we need to examine the cost estimates for the construction of peak load electricity generating capacity. For this purpose we choose cost

*These figures do not include owners' costs. For nuclear facilities these have been estimated to run as high as 40 percent of capital costs; for coal-fired plants, 25 percent. The conservation measures we have considered do not involve owners' costs of comparable magnitudes. Therefore, our estimates of capital savings through implementation of these programs are understated.

estimates for gas turbine facilities. According to our data base, the construction costs for a 133 MWe gas turbine facility are $17 million (1974 dollars) spread over a two-and-a-half year construction period. (Owners' costs, in this case, are estimated to be an additional 10 percent.) The full implementation of the passive solar housing program which we have postulated would eliminate the need for ten such facilities by 1981, an an additional ten facilities for each subsequent five-year period. This would free investment capital of approximately $170 million (1974 dollars) by 1981 and a total of $510 million by 1991. These thirty plants would require 39 X 10^{12} BTU of fuel, 204 man-years of labor and $6.9 million (1974 dollars) annually for their operation after 1991.

Table 24 shows that a single gas turbine facility of 133 MWe capacity requires 120 man-years of labor to construct. The indirect labor required by the materials embodied in such a facility is estimated to be 330 man-years. This brings total manpower called for by each new gas turbine plant to 450 man-years. If we postulate, as explained above, ten facilities to meet the additional peak load demand between 1977 and 1981, we arrive at a total manpower requirement of 4500 man-years over this interval. In the subsequent five-year intervals equal amounts would be required.

We now examine the manpower requirements for the two alternatives. On the level of direct labor requirements we have assumed that no additional manpower would be called for in the actual construction of passive solar housing beyond that which would have been employed in constructing an equivalent amount of conventional housing. However, the indirect manpower required for the manufacture of the additional materials is estimated to be 3000 man-years between 1977 and 1981 and an additional 3000 man-years for each subsequent period.

To summarize, our estimates indicate that over the 15-year interval 1977 to 1991, 13,500 man-years of labor and $510 million of capital would be released by reduced construction of gas turbines. Offsetting this would be 9000 man-years of labor at no additional capital cost for the passive solar housing program.

Both the passive solar housing and the retrofit insulation programs result in savings of natural gas (see Table 25). The cumulative savings are large enough to remove the need for two SNG plants which would be located outside California. The cancellation of these plants would release $1.5 billion (1974 dollars) of capital outlays and would eliminate 56,000 man-years of labor. The annual operating requirements for the two plants amount to $15 million and 1000 man-years. The coal input to these plants is 55 X 10^3 tons/day.

The retrofit insulation program, which provides the larger portion of the gas savings, requires a capital outlay of $760 million (1974 dollars) and employs 8000 man-years of labor in the state. Contrasting these alternatives, we see that implementing this conservation program leads to increased capital expenditures and employment within California, whereas building the SNG plants leads to increased out-of-state investment and employment. Furthermore, the California economy would benefit from the indirect impacts of the retrofit insulation program.

DISCUSSION

While the arithmetic comparisons presented above may seem relatively straightforward, the overall impact on the level of economic activity of pursuing a conservation program as against constructing and operating a conventional energy facility is by no means straightforward. Obviating the need for a power plant or an SNG facility means that certain amounts of capital and manpower will be available for investment in other sectors of the economy. Whether or not these resources are absorbed elsewhere depends on the level of demand for capital goods, which, of course, is dependent upon the level of aggregate demand. The impact of investment differs in a slack economy compared to one in which resources are fully employed. One cannot, therefore, make a statement *a priori* as to what the overall economic impacts of undertaking, or not undertaking, a particular investment project are apt to be.

The problem is further complicated by the fact that capital and labor are combined in varying proportions in different uses, i.e., some

avenues of investment are more labor intensive (less capital intensive) than others. High levels of unemployment combined with relative tightness in capital markets indicate that, other things remaining the same, there are grounds for preferring more labor intensive avenues of investment.

The conservation measures we examined would not increase the demand for labor as much as the power plant construction that would be displaced by these measures. This does not necessarily imply that unemployment will increase in California as a result of energy conservation. First, the labor requirements for other conservation measures may be greater or less than the requirements for those measures we have considered. Second, a projection of the labor required for construction does not imply that an equivalent number of workers are available for employment. If, however, unemployment exists, the financial and real resources that would have been used for power plant construction might be channeled to other sectors of the California economy. This in turn would stimulate income and employment. Expansion in these sectors most probably would involve new construction, so the demand for those occupations directly involved in construction would rise. As 80 percent of the industries are more labor intensive than the energy industries in terms of operation, there appear to be opportunities for net employment gains (see Chapter II).

We have discussed the impacts from obviating power plants in the the most direct terms possible—the construction, maintenance, and fuel requirements. There are, however, other significant savings such as the land that need not be set aside for power plant sites, distribution facilities and transmission lines, the lower demand for water, and the reduction in pollutant emissions and radioactive wastes from extraction and generation facilities.

LIMITATIONS OF THE STUDY

There are a number of limitations that the reader should bear in mind when interpreting the data and conclusions from this report. The study is focused on the economic impacts of alternative plans for energy facilities construction and operation. We do not examine energy use in the California economy, nor do we trace the impacts of changes in energy supply to other sectors in the economy.

In both models there are assumptions of linearity that represent abstractions from the way the economy actually functions. In the California Energy Supply Model, used to estimate direct economic impacts, the materials and manpower data for the energy facilities pertain to typical or "nominal" facilities. Thus there is no allowance for scaling construction and operation requirements to match varying plant sizes.

In the input-output model used to estimate indirect economic impacts, inputs scale linearly with outputs. By using the same model over the fifteen-year period we do not take into account any structural changes that might take place in the economy. A fixed structural relationship may be realistic in the short run, but in the long run the input mix may change for a variety of reasons (for example, the turnover of capital stock). Therefore, the assumptions of fixed input-output relationships is a limitation when making long-range projections. Moreover, the inputs and outputs are assumed to increase enough to satisfy the final demands. Thus capacity constraints are not accounted for in this model.

Another set of limitations concerns the temporal, spatial, and systemic bounds we assumed. The fifteen-year time horizon is attributable to the 1995 cut-off of the utilities' projections. Furthermore, the utilities' plans call for large additions to capacity in 1995, the final year included in our scenarios. This scheduling, combined with the fact that many of the facilities are large, discrete units, leads to fluctuations in the time distribution of construction requirements. It also implies that significant portions of construction will take place beyond our assumed time horizon.

The California Energy Supply Model simulates energy development in California and the Southern Mountain Region. Therefore we do not account for the capital and manpower needed to produce Alaskan or imported oil and

gas. Moreover, we do not know whether the indirect economic impacts occur in or out of state. We have assumed that the same fraction of total output by sector will be produced in-state as in 1972.

Our analysis of alternative investment strategies requires the drawing of boundaries within which this partial analysis is performed. Where these boundaries are drawn with regard to indirect impacts, fuel and capacity savings, appliance size reduction, etc. might effect the results.

Several important data limitations should be noted. Most of the data for characterizing the facilities in the energy supply model were obtained from the Bechtel Corporation. These data were developed in 1974 and hence reflect the engineering estimates available at that time. The accuracy of the data is estimated to range from ± ten percent to ± fifty percent. For new energy technologies, the data are even less reliable. They pertain to proposed facilities or represent extrapolations from small-scale existing facilities.

Our analysis of the potential impacts of energy conservation measures is based on a series of assumptions about the magnitude of these measures and the potential for energy and capacity savings. Due to the paucity of data, in some cases these assumptions are tantamount to educated guesses. For example, we did not estimate implementation levels. Rather we assumed as extensive an implementation level as possible given the existing stock of residential and commercial buildings and the projected growth rate of new residences. Furthermore, as we consider only three conservation measures, the impacts estimated in scenario 3 should not be viewed as the impacts from a full-scale energy conservation program.

We have assumed a "typical" dwelling in calculating material requirements and energy savings. The savings were calculated with computer simulation models that have not been fully verified. These savings then must be translated into capacity savings. To make this translation both a method and data are needed. To date there appears to be no standard methodology for making this calculation. Also, data regarding the contribution by end use to peak or base load power demand are unavailable. Therefore our capacity savings estimates should be regarded only as approximations.

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APPENDICES

0 0 0 0 4 7 0 0 0 5 5

APPENDIX A

METHODOLOGIES AND MODELS FOR ESTIMATING ECONOMIC IMPACTS

ESTIMATION OF DIRECT IMPACTS

A California Energy Model was developed to estimate the direct impacts* of construction and operation of energy and related transportation facilities. This model is based on the data developed for the Energy Supply Planning Model by the Bechtel Corporation.[1] Data for nonconventional facilities were acquired and developed at LBL. The indirect economic impacts were estimated using a California input-output table. This table has 334 sectors, reflecting the California interindustry structure for 1972.

The California Energy Supply Model consists of several submodels, shown as circles in Fig. A-1. These submodels allow the exploration of energy supply options to California. The model converts a future fuel and electricity supply mix into a yearly schedule of electric generation, fuel production, and transportation facilities. It will also calculate the set of direct resources and pollutant emissions associated with the construction and operation of these facilities for each year. The sequence proceeds as follows:

Inputs:

- Annual schedules are specified for i) gas demand, ii) oil demand, iii) electrical generating capacity, and iv) nonconventional energy supply facilities.
- Gas and oil supply constraints and characteristics are also specified.

Calculations Performed by Model

- The computer program then calculates the necessary energy facility construction schedules and the fuel flows required for these facilities.
- These fuel flows are then converted into transportation facility schedules.

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*Direct impacts include all impacts arising directly out of the construction and operation of any facility. Indirect impacts include impacts due to other activities related to the construction and operation of that facility. For example, the manpower required to construct a power plant would be a direct requirement whereas the manpower required to make steel used in constructing the power plant would be an indirect requirement.

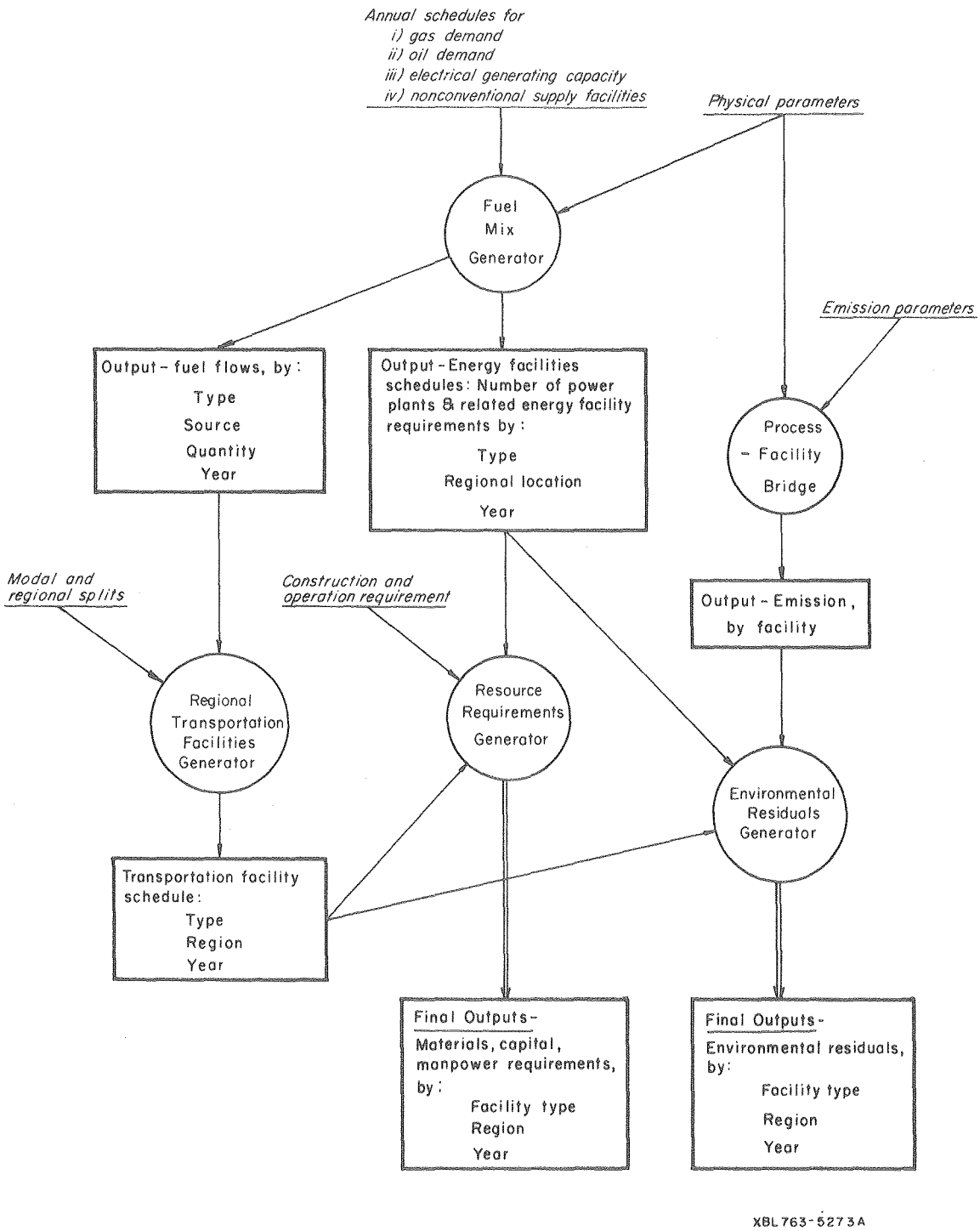

Fig. A-1 California Energy Supply Model

Model Outputs

- The program next calculates the capital, manpower and equipment required to construct and operate these facilities.
- A separate program can compute the environmental pollutants emitted by these facilities.

Output Format

- Finally the output from the two previous steps is reassembled and printed in a tabular and graphical format.

Although the model is capable of calculating pollutant emissions for all facilities, for the purposes of this study pollutant emissions due only to power plants were estimated. These are described in detail in a separate report.

Fuel Chains and Input Data for the Model

As noted in Table 6,* the inputs to an energy scenario must be spelled out in detail. Fuel and energy flows into California are shown schematically in Fig. A-2, with basic facilities and the interlinking flows indicated. These links represent both present and potential flows for meeting California energy requirements. Table A-1 lists these facilities and the resources and manpower required for their construction and operation.

Gas Supply

Crude oil and natural gas form the bulk of energy supplied to California. Natural gas for California at present comes from California, Texas, the Rocky Mountain states and Canada. As existing onshore sources are depleted, additional gas supplies are expected to come from Alaska, Indonesia and offshore wells. Table 8 shows a list of gas supply sources and their expected production for each scenario. Imported natural gas will be transported to California as liquefied natural gas (LNG) in tankers. Alaskan gas, either from the North Slope or Cook Inlet, will come to California either as LNG or by pipeline. Significant quantities

*The table numbers without the prefix A refer to tables in the main text.

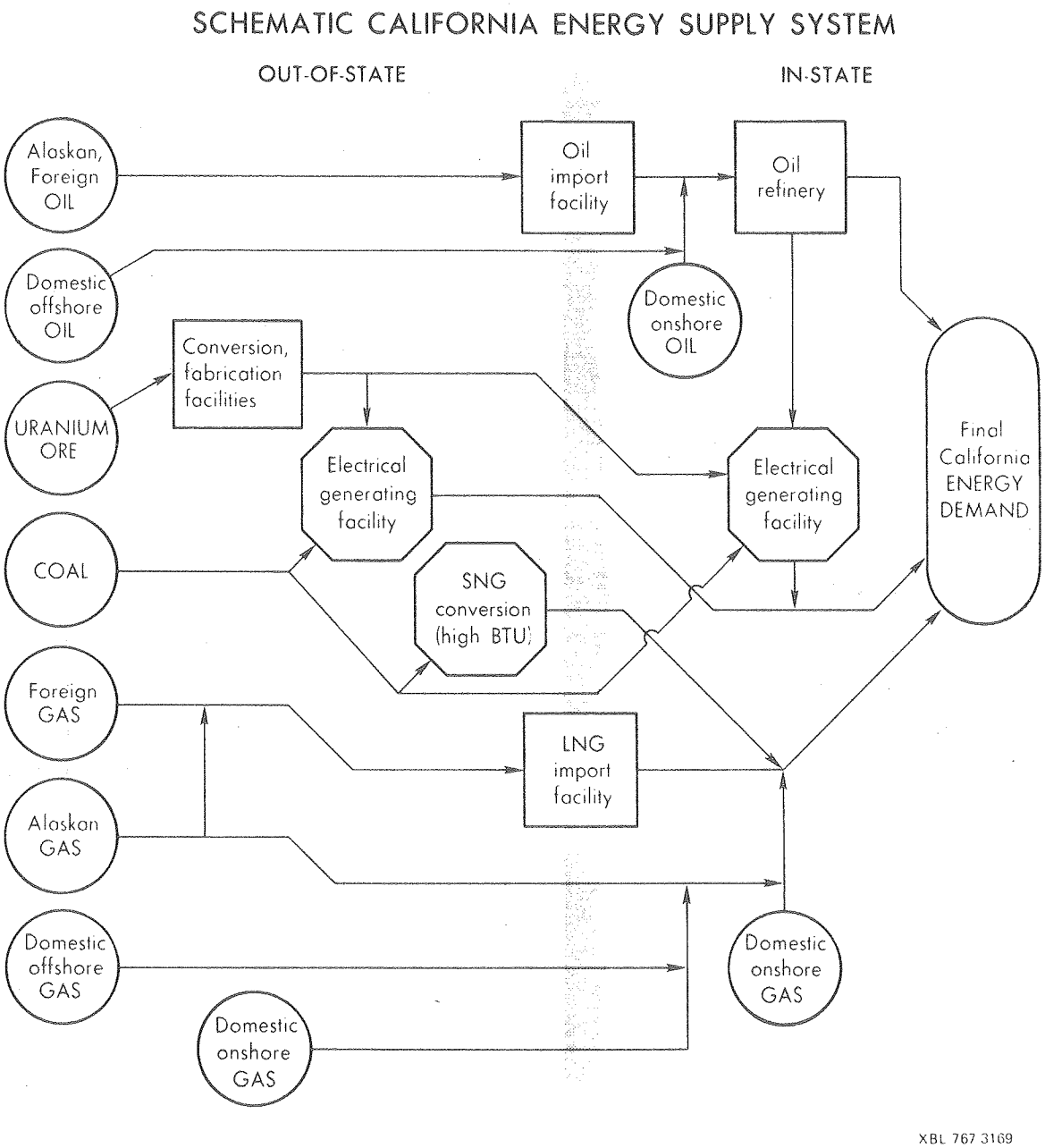
SCHEMATIC CALIFORNIA ENERGY SUPPLY SYSTEM
OUT-OF-STATE
IN-STATE
Alaskan, Foreign OIL
Oil import facility
Oil refinery
Domestic offshore OIL
Domestic onshore OIL
Conversion, fabrication facilities
URANIUM ORE
Electrical generating facility
Electrical generating facility
Final California ENERGY DEMAND
COAL
SNG conversion (high BTU)
Foreign GAS
LNG import facility
Alaskan GAS
Domestic offshore GAS
Domestic onshore GAS
Domestic onshore GAS
XBL 767 3169

Fig. A-2

Table A-1

Cost and Manpower Data for Nominal Facilities

Facilities	Nominal Size[a]	CONSTRUCTION REQUIREMENTS		OPERATION REQUIREMENTS	
		Total Cost[b] in million (1974) dollars	Manpower[c] in 10^3 man-hours	Cost[d] in million (1974) dollars per year	Manpower in man-years per year
I. ENERGY FACILITIES					
1. Onshore oil production	250 bbl/day	5.10	94.00	0.04	5.12
2. Offshore oil production	4000 bbl/day	32.00	287.00	0.35	16.17
3. Low-gasoline refiner	200,000 bbl/day	430.00	13,150.00	72.73	402.80
4. Onshore oil import	1×10^6 bbl/day	95.00	1,890.00	3.56	177.00
5. Onshore gas production	3×10^6 ft^3/day	4.70	94.00	0.032	9.53
6. Offshore gas production	50×10^6 ft^3/day	68.00	720.00	0.487	17.18
7. LNG import terminal	6×10^6 ST/year	420.00	9,950.00	8.712	96.00
8. Surface western coal mine		44.40	794.00	5.65	275.90
9. Surface uranium mine	1200 ST/day	14.00	532.00	2.31	178.00
10. Uranium mill	1000 ST/day	7.00	217.00	1.68	111.00
11. LWR fuel fabrication (no PU recycle)	660 ST U/year	48.00	1,365.00	34.46	503.00
12. Oil-fired power plant	800 MWe	180.00	4,400.00	2.60	84.00
13. Coal-fired power plant (with SO_2 removal)	800 MWe	340.00	7,700.00	6.61	195.00
14. Combined cycle power plant	400 MWe	66.00	1,320.00	1.46	26.00
15. Gas turbine power plant	133 MWe	17.00	224.00	0.23	6.80
16. Light water reactor	1100 MWe	460.00	12,000.00	4.64	112.10
17. Dam and hydroelectric power plant	200 MWe	80.00	2,385.00	0.27	12.20
18. Pumped storage	1000 MWe	225.00	6,430.00	0.56	25.00
19. Geothermal power plant	200 MWe	120.00	992.00	0.74	83.00
20. Solar power plant	100 MWe	104.00	1,070.00	11.20	--
21. Waste-fired power plant	133 MWe	167.00	3,424.00	20.00	300.00
22. Active solar heating	2.1×10^{12} BTU/season	234.00	7,960.00	6.203	375.00
23. Wind turbine generator	4 MWe	2.007	16.89	0.06	--
24. Coal Gasification	250×10^6 ft^3/day	750.00	20,697.60	7.50	590.00

Table A-1 (Continued)

Cost and Manpower Data for Nominal Facilities

Facilities	Nominal Size[a]	CONSTRUCTION REQUIREMENTS		OPERATION REQUIREMENTS	
		Total Cost[b] in million (1974) dollars	Manpower[c] in 10^3 man-hours	Cost[d] in million (1974) dollars per year	Manpower in man-years per year
II. TRANSPORTATION FACILITIES					
1. Crude oil pipeline	800,000 bbl/day, 1000 miles	406.00	6500.00	20.30	115.00
2. Oil tanker	90,000 DWT	32.00	--	3.19	82.91
3. Oil tank truck	9500 gallons	0.07	--	0.02	2.18
4. Products pipeline	70,000 bbl/day,100 mi.	15.60	316.00	0.13	15.80
5. Hot oil pipeline	40,000 bbl/day,50 mi.	12.70	212.00	0.18	13.20
6. Refined products bulk station	69,000 bbl/day	6.80	120.00	0.05	12.90
7. Gas pipeline	830 X 10^6 ft^3/day	430.00	6500.00	14.811	139.00
8. LNG - tanker	2.6 X 10^6 ft^3/day	100.00	--	4.572	90.77
9. Gas distribution facility	50 X 10^6 ft^3/day	30.00	760.00	.589	82.32
10. Rail line	40 miles, single track	12.30	289.00	0.17	18.04
11. Coal train	10,500 ST	4.60	--	0.85	29.70
12. Coal truck	25 ST	0.05	--	0.02	1.35
13. 230 kV AC transmission line	480 MWe,500 miles	95.00	2430.00	0.03	4.21
14. 345 kV AC transmission line	960 MWe,500 miles	120.00	3255.00	0.05	7.19
15. 500 kV AC transmission line	2080 MWe,500 miles	188.00	4555.00	0.07	9.40
16. Electricity distribution	131.6 MWe	41.00	1100.00	0.27	23.30
17. Conventional rail	10,500 ST	4.60	--	0.85	29.70

a. Unit Abbreviations: MWe - megawatts, electric; ST - short ton; DWT - dead weight ton

b. Excluding owners' cost.

c. Manpower figures not included for non-stationary facilities.

d. Excluding labor and fuel costs.

of synthetic natural gas (SNG) are expected by 1990 from the Rocky Mountain states, which will be transported by pipeline.

The model simulates the flow of gas into and within California and identifies the facilities required to produce and transport the natural gas. For domestic flows the facilities included are onshore gas production wells, offshore gas production wells, and gas pipelines. For imported gas the facilities are LNG import terminals and LNG tankers. Based on the estimated annual supply of natural gas to California the model calculates the nominal numbers of each of these facilities required to provide the gas.

Oil Supply

Crude oil is available from onshore and offshore wells and from imports. Onshore crude oil production in California is expected to decline over the next 20 years, whereas California offshore production is expected to peak in 1990. Additional oil requirements would be met by Alaskan oil and foreign imports. Crude oil supply sources and quantities for the scenarios are shown in Table 9. It is assumed that the entire quantity of crude oil would be refined in California and that California would not import any refined products. Crude oil is assumed to form the only major input to the refineries. These refineries are assumed to produce transportation fuels, power plant fuels, and feedstocks for industry. In the model, the fraction of different types of fuel produced can be varied to meet the necessary demand, i.e., it is implicitly assumed that refineries can change the product fraction to meet the changes in demand for each type of fuel.

Gas and Oil Demand

The California energy flow simulation process starts with the stipulation of gas flows to California and then proceeds to calculate the flow of petroleum products. If the demand for natural gas is in excess of the available supplies, highest priority users are satisfied first. The unsatisfied demand for natural gas is then met by oil supplies. This

demand for fuel oil along with transportation, power plant and non-fuel demands determine the total crude oil requirements in a given year. Power plant fuel requirements are calculated based on the twenty-year projected mix of power plants.

Supplies of natural gas are allocated to different types of natural gas demands in the following order of priority.[2]

(i) Firm Gas Demand

(ii) Interruptible Gas Demand

(iii) Residential and Commercial Oil Demand

(iv) Industry Fuel Oil Demand

In the first scenario the first two categories include the demands projected by the California Public Utilities Commission for natural gas consumption in the state. Categories (iii) and (iv) are the projected demands for oil which can be met by gas supplies. It is not clear whether available projections for categories (ii), (iii) and (iv) are entirely independent of each other. As a first cut they are assumed to be independent, subject to later revisions.

The combined annual demand for these four categories is expected to exceed the natural gas supply available in a given year. The unsatisfied gas demand is then met by residual fuel oil. Demands for oil supplies are categorized as follows:

(i) Transportation

(ii) Electricity Generation

  (a) Low sulfur heavy fuel oil

  (b) Distillate oil

(iii) Industry Non-Fuel Demand

(iv) Unsatisfied Gas Demand

Annual demand projections for categories (i) and (iii) were obtained from Ref. 3 for the first scenario. Fuel requirements for category (ii), power plants, are based on the annual schedule of power plants coming on-line by 1995. Residual oil is consumed by both gas turbine and combined cycle power plants. These power plants are located in California only. Table A-2 shows the power plant and fuel characteristics assumed in the model. Category (iv), unsatisfied gas demand, is the excess demand for gas which is substituted for by oil supplies. These

Table A-2

Power Plant and Fuel Characteristics

Power Plant	Capacity Factor[a]	Thermal Efficiency	Fuel	Heat Content million BTU/Unit
1. Oil	0.51	0.38	Low sulfur Heavy fuel oil	6.287/bbl
2. Coal	0.66	0.38	Strip-mined coal	24/ton
3. Nuclear (LWR)	0.71	0.32	Enriched uranium	2.5×10^6/ton of uranium .033 ^{235}U .0025 tails
4. Combined Cycle	0.56	0.40	Distillate oil	5.88/bbl
5. Gas Turbine	0.10	0.27	Distillate oil	5.88/bbl

a. Weighted averages of utility submissions to CERCDC. Annual capacity factors used in the model vary from year to year based on utility submissions.

four demands are converted from physical units to a common unit of energy (BTU's) using conversion factors shown in Table A-3.

Crude oil requirements (in barrels) are computed by converting the total BTU requirements determined above into barrels of oil required as input to the refineries. Crude oil for these refineries is allocated by the model from the three major sources in the following order of priority: 1) California oil from onshore wells; 2) oil from the outer continental shelf of California; and 3) imported oil from Alaska and from foreign countries.

Coal

Coal-burning power plants may be located in California and the Southern Mountain Region (consisting of the states of Arizona, Colorado, Nevada, New Mexico and Utah). Power plants at both locations are assumed to burn the same type of strip-mined coal, all of which is mined in the Southern Mountain Region. Coal is transported via conventional or unit trains and by coal trucks from the coal mines directly to the power plants. The fuel chain includes two categories of energy facilities: coal mines and coal-burning power plants; and four types of transportation facilities: unit trains, conventional trains, coal trucks and fixed railroad facilities.

The model calculates the amount of coal mined to meet the requirements of the coal-burning power plants in the two regions. We have used an average heat content of 12,000 BTU/lb for coal found in the Southern Mountain Region. This comes from an assessment of the coal reserve base for the Southern Mountain Region, weighted by the mean heat content of each coal type. Based on this analysis we assume an average value of ten percent for the ash content and 1.0 percent for the sulfur content for coal in this region. These data are corroborated by a recent U.S. Geological Survey study[4] of remaining identified coal resources in the U.S. from which one obtains a similar heat content.

Table A-3

Conversion Factors[a]

	Demand Types	Million BTU/barrel
(i)	Transportation Gasoline	5.253
(ii)	Electricity Generation	
	(a) Residual[b]	6.287
	(b) Distillate	5.880
(iii)	Industry Non-Fuel Demand	5.506
(iv)	Unsatisfied Gas Demand[b]	6.287
(v)	Crude Petroleum	5.800
(vi)	Natural Gas	1032 BTU/ft^3

a. Knecht, R. L., and C. W. Bullard, "Direct Energy Use in the U. S. Economy, 1971", Center for Advanced Computation, University of Illinois at Urbana-Champaign, Report no. CAC-43, April 1975.

b. CERCDC Quarterly Fuel and Energy Summary, Vol.1, No.4.

Uranium

Light water reactors are the only facilities in the model that use uranium as a fuel. The reactors supplying electricity to California are located in California and the Southern Mountain Region. The fuel chain begins with uranium mining and milling activities, which are assumed to occur in the Southern Mountain Region only. Further processing of uranium ore, except for fuel fabrication, is assumed to occur in states other than California and the Southern Mountain Region and no resource requirements are calculated for these facilities. Fuel fabrication facilities are located in California only if the requirements exceed 20 percent of the nominal size of the fabrication facility; otherwise this facility is assumed to be located outside the two regions under consideration. Uranium transportation is not considered as the quantities were deemed too small to make a significant change in the impacts under consideration.

The model calculates the amount of uranium mined in the Southern Mountain Region and the amount of uranium fuel required by the power plants. These fuel requirements are based upon 3.3 percent enrichment in ^{235}U; 0.25 percent ^{235}U in the enrichment tails; an average thermal specific power of 30 MW/metric ton of uranium fuel; and an uranium ore concentration of 0.15 percent.

No uranium or plutonium recycling is assumed, so that fuel requirements are based on flows through the reactor; therefore, our calculations set an upper limit on the amount of uranium needed. If uranium and plutonium are recycled, the amount of uranium to be mined could be less by as much as 30 percent. Since there is presently considerable uncertainty regarding fuel reprocessing and waste storage, these facilities are not specifically included in the model.

The operation of fuel chains is simulated in the fuel mix generator (see Fig. A-1). This program also accepts all the input data outlined earlier along with relevant data on each type of nominal facility. Based on this information the program then calculates:

- Annual fuel flows by type, source and quantity, and
- the energy facilities' schedules, which specify the number of nominal power plants and related nominal energy facility requirements by type, regional location and year.

The fuel flows are then used to determine the types and sites of nominal transportation facilities required to meet the demand for fuels. Fuel flows include transmission of electricity.

Having determined the number of nominal energy and transportation facilities that need to be constructed, the program next calculates the manpower, capital and materials resources required to construct and operate these facilities. These resources are computed for each region and for each year until 1990. Tables A-4 and A-5 show the detailed list of resources included in the model. Data for these resources were acquired from the Energy Supply Planning Model.[1] The capital resources serve as a final demand vector which stimulates indirect production in the California and U.S. economies. The estimations of these indirect impacts in California using an input-output table for the state is described in the next section.

ESTIMATION OF INDIRECT ECONOMIC IMPACTS

The indirect economic impacts of a change in final demand can be estimated using an input-output table. In an input-output table the economy is broken up into sectors such as coal mining, automobile manufacturing, or retail trade. Each element in the table is the dollar purchases by one sector, of the output of another sector, during one year. Reading across the rows shows the sales of a given commodity to all sectors including final demand. (Final demand is the consumption by ultimate consumers such as households, government, exports, and capital formation.) Reading down a column shows all the inputs to a given sector including value added which represents payments to the factor of production (land, labor, capital, etc.). The sum of all the elements in a column is called the gross output of that sector. If each element in the column is divided by the gross output, the resulting vector of technical coefficients shows the inputs from each sector needed to produce one dollar's worth of output in that sector. Insofar as these technical coefficients do not change significantly over the time period of this study, an input-output table can be used to calculate the changes in gross output due to a change in final demand.

Table A-4

California Energy Supply Model

Construction Resource Requirements

Manpower in Thousands of Man hours

1	Chemical Engineers
2	Civil Engineers
3	Electrical Engineers
4	Mechanical Engineers
5	Mining Engineers
6	Nuclear Engineers
7	Geological Engineers
8	Petroleum Engineers
9	Other Engineers
10	Total Engineers
11	Total Designers & Draftsmen
12	Total Supervisors & Managers
13	Total Technical
14	Total Nontechnical (Nonmanual)
15	Pipefitters
16	Pipefitter/Welders
17	Electricians
18	Boilermakers
19	Boilermakers/Welders
20	Iron Workers
21	Carpenters
22	Operating Engineers
23	Other Major Skills
24	Total Major Skills
25	Other Craftsmen
26	Total Craftsmen
27	Total Teamsters & Laborers
28	Manpower Total

Table A-4 (Continued)

	Materials
29	Refined Products (Tons)
30	Cement (Tons)
31	Ready Mixed Concrete (Tons)
32	Pipe & Tubing (Less than 24" D)(Tons)
33	Pipe & Tubing (24" D & Greater)(Tons)
34	Oil Country Tubular Goods (Tons)
35	Steel Forgings(Tons)
36	Iron & Steel Castings (Tons)
37	Structural Steel (Tons)
38	Rebar (Tons)
39	Valves (24" D & Greater)(Items)
40	Valves (24" D & Greater)(Tons)
41	Steam Turbogenerator Sets (1000 HP)
42	Steam Turbines W/O Generators (1000 HP)
43	Gas Turbogenerator Sets (1000 HP)
44	Gas Turbines W/O Generators (1000 HP)
45	Draglines (Cubic Yards)
46	Draglines (Tons)
47	Drill Rigs (Item-Years)
48	Pumps & Drives (100 HP)(Items)
49	Pumps & Drives (100 HP)(Tons)
50	Compressors & Drives (1000 HP)(Items)
51	Compressors & Drives (1000 HP)(Tons)
52	Heat Exchangers (1000 Sq Ft Surface)
53	Pressure Vessels (1½" Plate)(Tons)
54	Boilers (10^6 BTU/hr)
55	Nuclear Steam Supply Systems (GWe)

Table A-4 (Continued)

Construction Costs in Million (1974) Dollars

56	Wood Products (20)*
57	Chemicals & Allied Products (27,28,30,32)
58	Petroleum Products (31)
59	Stone & Clay Products (36)
60	Primary Iron & Steel Products (37)
61	Primary Nonferrous Metals (38)
62	Fabricated Structural Products (40)
63	Other Fabricated Products (42)
64	Materials Subtotal
65	HVAC Heating & Cooling Units (52)
66	HVAC Ductwork & Accessories (40)
67	Turbines (43)
68	Construction, Mining & Oil Field Eqp (45)
69	Gas Welding Sets & Metalworking Eqp (47)
70	Electric Welding Sets (53)
71	Materials Handling Equipment (46)
72	General Industry Equipment (49)
73	Instrumentation & Controls (62)
74	Electrical Equipment (53)
75	Fabricated Plate Products (40)
76	Miscellaneous (1-68, Except Above)
77	Equipment Subtotal
78	Construction Capital Cost Total

*Figures in parentheses are BEA input-output sector numbers.

Table A-5

California Energy Supply Model

Operation Resource Requirements

	Manpower in Man-years
1	Chemical Engineers
2	Civil Engineers
3	Electrical Engineers
4	Mechanical Engineers
5	Mining Engineers
6	Nuclear Engineers
7	Geological Engineers
8	Petroleum Engineers
9	Other Engineers
10	Total Engineers
11	Total Designers & Draftsmen
12	Total Supervisors & Managers
13	Total Other Technical
14	Total Technical
15	Total Nontechnical (Nonmanual)
16	Pipefitters
17	Pipefitter/Welders
18	Electricians
19	Boilermakers
20	Boilermakers/Welders
21	Iron Workers
22	Carpenters
23	Equipment Operators
24	Other Operators
25	Underground Miners
26	Welders, Unclassified
27	Other Major Skills
28	Total Major Skills
29	Other Craftsmen
30	Total Craftsmen
31	Total Teamsters & Laborers
32	Manpower Total

Table A-5 (Continued)

Operating Costs in Million (1974) Dollars

33	Lumber & Wood Products (20,21)*
34	Paper & Paper Products (24-26)
35	Chemicals & Allied Materials (27-32)
36	Stone, Clay & Glass Products (35,36)
37	Nonferrous Metals (38)
38	Metal Products (39-42)
39	Miscellaneous
40	Total Materials & Supplies
41	Nonelectrical Machinery (43-50,52)
42	Electrical Equipment (53-58)
43	Transportation Equipment (59-61)
44	Instruments & Controls (62,63)
45	Miscellaneous (64)
46	Total Equipment
47	Fuel (Heat) (68)
48	Electricity (68)
49	Water (68)
50	Total Utilities

*Figures in parentheses are BEA input-output sector numbers.

To do this, the table is first converted into the direct requirements matrix A by dividing each column by the gross output in that sector. The Leontief inverse $(I-A)^{-1}$ is computed and postmultiplied by the change in the final demand vector ΔY to give the change in gross output:

$$\Delta X = (I-A)^{-1} \cdot \Delta Y. \qquad \text{(A-1)}$$

The change in value added and employment in each sector is assumed to be proportional to the change in gross output in that sector.

$$\begin{aligned} \Delta V_i &= v_i \Delta X_i \\ \Delta E_i &= e_i \Delta X_i \end{aligned} \qquad \text{(A-2)}$$

The coefficients v_i and e_i are the value added and employment in sector i divided by the sectoral gross output from the I-O table.

To calculate the indirect impacts a preliminary version of the 368-sector California Input-Output Table being developed by LBL for ERDA has been used. The California table is based on the technical coefficients derived by updating the 1967 national table to 1972.[5] For convenience we aggregated the California table to 87 sectors deleting those sectors which do not exist in the state at the 368-sector level. At the 87-sector level the missing sectors are Coal Mining and Tobacco Manufacturing. The table does not include the special industries that are used by BEA for accounting purposes. The Leontief inverse was calculated for the remaining 79 productive sectors. The calculation of indirect impacts is done in constant 1972 dollars, then inflated to 1974 dollars.

Construction of Final Demand Vectors

The steps in constructing the final demand vectors from the direct requirements calculated by the Energy Supply Model are shown schematically in Fig. A-3. The model output gives the construction requirements from 1974 to 1990 for the twenty categories of materials and equipment listed in Table A-4. A total capital cost is also given. All these data are expressed in purchaser's prices in third quarter 1974 dollars. The first step is to

INDIRECT ECONOMIC IMPACTS

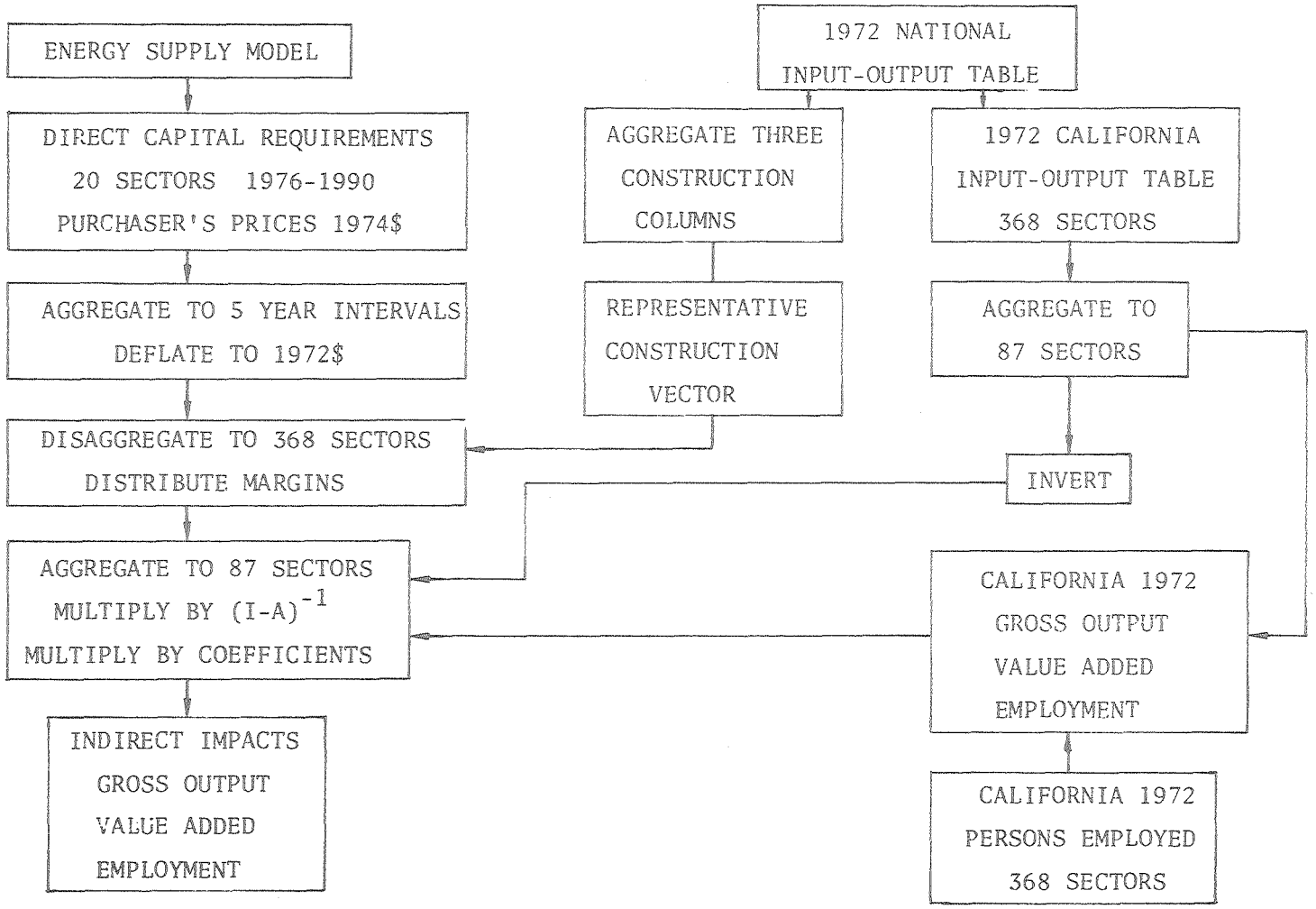

Figure A-3

aggregate these requirements to five-year intervals starting with 1976 and to deflate the data to constant 1972 dollars. This was done using deflators obtained from CAC and the Survey of Current Business.[6,7]

Of the twenty requirements categories only six correspond to the BEA 368-sector classification; the rest correspond to two digit or groups of two-digit codes. Because data were available at the 368-sector level on the transportation costs and trade margins needed to convert purchaser's prices to producer prices, we decided to disaggregate the requirements to 368 sectors. The proportions used to disaggregate the requirements were derived in the following manner. A representative final demand vector was constructed by adding the columns from the 1972 national I-O table for 1) new construction of non-residential buildings; 2) new construction of public utilities; and 3) gross private capital formation excluding the five new construction rows. This 368-order final demand vector is an approximation to the requirements for both structures and equipment needed in constructing energy facilities. The requirements calculated by the model were disaggregated according to these proportions. Transportation costs and trade margins[6,8] were subtracted from each producing sector and assigned to the appropriate transportation or trade sector. The remaining construction costs not included in the twenty requirements categories were allocated to the service and government sectors, imports and value added, in proportion to the two construction sectors contained in the representative final demand vector.

The final demand vectors for nominal facilities are derived from the construction requirements in a similar manner. The only difference is that instead of aggregating over a five-year period for each category, the aggregation is over the construction time of the project. Thus the final demand vector and the resulting indirect impacts do not have a time period associated with them.

The final demand vectors for the alternative investments are calculated much more simply. The data are categorized by SIC code and input-output sector. The requirements, which are in 1976 dollars, are deflated to 1972 dollars using wholesale price indices[9] and entered in the appropriate sector. Finally, trade margins and transportation costs are distributed to the proper sectors.

Changes in Gross Output, Value Added and Employment

The interpretation of the indirect impacts depends on the method of constructing the California input-output table. Each column of the 368-sector national table is divided by the corresponding national gross output. This gives a set of national coefficients which are multiplied by the state gross outputs giving the columns of the state table. The resulting California table has 334 producing sectors. The final demand columns for personal consumption expenditures, capital formation and government purchases are appended. The rows of the table are permuted so that these 334 sectors are first. The remaining rows represent imports by each sector. The rows are then summed to get the total consumption by sector within the state. Finally, a sector-by-sector net trade balance is calculated by subtracting the consumption from the production. If the difference is positive, it is assumed to represent the value of the exports; if the difference is negative, it represents imports.

The electric utilities were handled as a special case because the mix of generating capacity in California is substantially different from the national mix. The general procedure is to disaggregate the electric utilities sector into several columns which represent generation by each of the technologies. The columns are expressed as coefficients by dividing each element by the column sum. A new electric utilities column is constructed by combining these coefficient columns weighted by the proportion of electricity generated in California by each new technology. This column, which represents the inputs required for generating electricity in California, is used in place of the national electric utilities column in constructing the California table.

The first step in carrying out this procedure is to combine the private, federal, and state and local utilities sectors of the 1972 national table into one sector. Five new columns representing electricity generation from coal,oil, gas, hydro and nuclear power were constructed. All the coal purchased by the electric utilities plus the transportation costs and trade margins were assigned to the coal generating column. Similarly, petroleum products were assigned to oil generation and natural gas from utilities to gas generation. The purchases of inorganic chemicals, which includes nuclear fuels, by the nuclear generating sector had

to be increased by $95 million to match the technical coefficients published by the Mitre Corporation.[10] It is reasonable to expect the amount of inorganic chemicals to be low in the 1972 national table because it is an update of the 1967 table when there was little nuclear power generated. There are no fuel inputs to the hydroelectric sector. The remaining inputs, except inter-utility sales, are disaggregated in proportion to the amount of electric energy produced by each of the five technologies. Similarly, additional columns for new generating technologies may be constructed using data from the Mitre Corporation.[10]

Before calculating the Leontief inverse, the 334 producing sectors were aggregated to the 87-sector level. The final demand vectors were aggregated to this level omitting those sectors which have no gross output in the state. To calculate the employment coefficients the 368-sector California person employed data[11] were similarly aggregated and then divided by the corresponding gross outputs.

The change in gross output ΔX was calculated using Eq. A-1. To take into account the importation of goods into the state we multiplied each element of ΔX by the ratio of production to consumption for that sector. Thus if half of the amount of a good that is consumed in California is produced there, then we assume that half of the change in production will occur within the state. Using this modified gross output vector in Eq. A-2, we calculate the indirect changes in employment and value added. The output and value added results are inflated to 1974 dollars using output deflators obtained from BEA.[12]

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11. Deane Merrill, Lawrence Berkeley Laboratory, "U.S. Employment for 368 Input-Output Sectors for 1963, 1967 and 1972," UCID-3757, July 1975.

12. Private communication from Jack Gottsigen, Bureau of Economic Analysis.

APPENDIX B

PASSIVE SOLAR HOUSING CONSTRUCTION*

INTRODUCTION

Solar energy is under active consideration as a replacement for fossil fuels. There are two general classes of residential solar energy systems, active and passive. In an active system, the sunlight heats a fluid that in turn is used for space heating, space cooling, and water heating. An active system usually requires a specialized collecting device and a heat storage device. In a passive system, the orientation, insulation, and glazing are designed to take maximum advantage of solar heat gain during the winter and to minimize heat gain during the summer. The building itself serves as the collector and heat storage device.

In a recent study, cost data are compared for approximately sixty solar heating, solar heating and cooling and/or hot water systems currently in residential use in Northern California.[6] The systems showed a wide range of technologies and costs. Systems costs for residential space heating and cooling ranged from $200 to $18,000 with an average cost of $3391; the cost per square foot ranged from $0.91 to $32.29. With the exception of five systems which were under $600, the data showed that these solar space heating and cooling systems have relatively high first costs compared with conventional systems. We have included active solar heating in our second scenario which emphasizes new technologies. The construction cost, taken from the Bechtel Energy Supply Planning Model, was $8100 per dwelling. Although the lifecycle costs for some solar systems are less than those for conventional systems, it is still generally true that when new housing is constructed the first costs are the determining factor in the selection of a heating and cooling system. Therefore, we also consider a cost competitive passive solar house as an attractive alternative.

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*Harold G. Nelson and Barbara A. Greene of LBL assisted in the preparation of this section.

The passive solar housing construction program we hypothesize is predicated upon a change in the state building code. The change would upgrade the insulation and glazing requirement to R-19 and R-30 insulation in the walls and ceilings, respectively, and double glazed and properly shaded windows. We also assume a minimum of half the window area is on the south wall and that adequate thermal mass is included in the structure for heat storage.

We postulate that all new single family and multifamily residences completed after 1976 will conform to the code change.* We use CERCDC estimates of housing construction rates[4] to scale our calculations of material requirements and savings. According to these housing construction estimates, the new single family and multifamily dwelling units will be constructed at a nearly constant rate of 205,000 per year over the next twenty years. Half of them will be single family and half multifamily. A "typical" multifamily dwelling contains four units. We perform four types of calculations: 1) energy savings; 2) capacity savings; 3) direct material and manpower requirements; and 4) indirect economic and employment impacts. For the fourth calculation, passive solar housing construction will be represented in the California input-output table by additions to the final demand vector. These additions are the increments in materials over those used in present housing construction that conforms to state code.

POTENTIAL ENERGY SAVINGS

The calculation of the energy savings in a passive solar house is an extremely complex problem. The major critical variables which affect the energy savings are climatic regions, site characteristics, type and design of residential structure, materials used in construction and resident participation in the system. Therefore, any energy savings calculation must be carefully evaluated for its assumptions and its inherent

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*Mobile homes are excluded from all calculations of material requirements and energy savings because the recent federal legislation on mobile home construction standards preempts state standards. See Federal Register, Vol. 41, No. 94, May 13, 1976, pl. 9855, Title 24 HUD, Part 3282.

limitations. Although we assumed overall dimensions for passive solar houses (Table B-1), we did not specify the details of the actual design. For example, we did not calculate the material requirements for several design features, such as shading and thermal mass, which also affect the energy savings. These design components have a wide range of material composition, each varying in its effectiveness. The thermal mass of the house may be increased by concrete slab flooring, sealed drums of water or even a baby grand piano. The greater the thermal mass, which acts as a storage system for the solar energy, the better the performance of the entire system. It is impossible, however, to account for these variations in detail in this calculation, although all affect the actual energy savings.

After examining the data from a variety of actual and computer simulated passive solar houses, we estimate that 60 percent of the heating and 60 percent of the cooling load of a typical house could be carried by a passive solar system.* Sixty percent represents the conservative end of the range of actual and predicted solar-carried heating and cooling loads,** both of which go as high as 100 percent.[2,7,8,11,14,15] However, this estimate must be used with caution because:

1. We do not have data for houses which are directly comparable with the prototype we assumed.
2. Calculations of energy savings in space heating and cooling are subject to the variations mentioned above that render a precise estimate impossible at this point.

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*If the insulation requirement for the walls is reduced from R-19 to R-11, thereby obviating the need for 2 X 6 stud construction, we estimate the savings factor would be reduced to approximately 50 percent.

**A calculation was performed by Barbara A. Greene and David Goldstein of LBL from data collected from an actual passive solar system during the winter of 1975-76. The data pertain to a 530 ft^2 conventional code building with single glazing, moveable insulation, and a thermal mass of approximately 400 gallons of water. The calculations showed that for an inside temperature range of 70-80°, the passive solar heating system would provide 73 percent of the heating load of the structure. (The outside temperature ranged from 35°F to 55°F.) During the summer of 1976 the temperature in the structure was monitored using a maximum-minimum thermometer. The inside temperature never rose above 80° during a four-day hot spell with outside temperatures over 100°F. No backup cooling system was required.

Table B-1

Dimensions of Housing Types

	Single Family Dwelling	Multifamily Dwelling[a]
Gross dimensions	38 X 38 X 8 ft	47 X 47 X 16 ft^2
Gross floor area	~1450 ft^2	~4400 (1100/unit[b]) ft^2
Gross ceiling area	1450 ft^2	2200 ft^2
Gross glazing area[c]	290 ft^2	880 ft^2
Gross wall area to be insulated	926 ft^2	2128 ft^2

[a]Two story structure, two units/story

[b]The trend in average square footage of duplexes and apartment houses has increased at a rate of approximately 1% per year. We have assumed an average of 1100 ft^2 per unit for multifamily dwellings for the next twenty years.

[c]Twenty percent of gross floor area as required by present Code

3. Computer simulations for calculating energy consumption in passive solar houses have not been fully verified. Further, the data upon which they are based are incomplete.

Consequently, the 60 percent savings assumed represents our best estimate to date, but is subject to revision as more information becomes available and the state of the art in computer simulation models of energy consumption in buildings advances.

The energy savings calculations were done by first estimating the unit energy consumption for residential space heating and air conditioning. These are statewide weighted averages using projected new housing construction rates,[4] applicance saturations,[9] and heating and cooling loads for new houses[9] built to Title 24 Standards.[18] The energy consumption for electric resistance heating and central air conditioning is based on computer simulation of the behavior of "typical" single family and multifamily residences constructed according to present state code.[18] The simulations were performed by the TWOZONE program using weather data for several locations within the state. This enabled us to assign heating and cooling loads to each of the five major utility service districts. These loads were multiplied by the number of units in single family or multifamily structures containing electric heating or cooling that are expected to be constructed in each service area during 1977.[4] This gave an expected statewide energy consumption for residential electric space heating and cooling for each type of dwelling unit. These figures when divided by the number of units of each type to be constructed gave the statewide annual unit energy consumption estimates shown in Table B-2.

To calculate the savings for gas heated homes the electric heating loads derived from the building simulations were multiplied by the expected number of gas heated units in each service area. The statewide average of these data was 8180 kwh per year for single family units and 3860 kwh per year in multifamily units. These were converted to BTU of gas consumed using a space heating efficiency of 60 percent; the results are shown in Table B-2.

For room air conditioners we use the estimate of approximately 920 kwh per year derived in Reference 9. Our estimates of future savings of energy and capacity in air conditioning are probably high because we have

not taken into account recent changes in the State Code which mandates increased air conditioner efficiencies. The new energy efficiency ratios (EER) have not been included in order to isolate the effect of passive solar housing construction.

Next the 60 percent savings factor is applied to the consumption in each dwelling unit to get the savings at the point of end use. The unit savings were multiplied by the number of units projected,[4] adjusted for saturation rates in new construction, and corrected for transmission losses to arrive at the statewide savings.

POTENTIAL FUEL AND CAPACITY SAVINGS

We assume that the reduction in air conditioning load in the passive solar houses is achieved by the installation of air conditioners with 60 percent smaller capacity. This implies the average operating time remains constant. The assumption appears reasonable because consumers can reduce their first costs by buying smaller air conditioners.

Currently central air conditioners in residential buildings range in size from two to five tons (one ton = 12,000 BTU/hr). The average size appears to be at the low end of this range.[13] We examined a scatter plot of the cooling effect (measured in BTU's/hr) versus the input power (measured in kilowatts) for central air conditioners. (See Ref.9, App. A, Fig. A-4.3.) At the low end of the range of central air conditioners, these data indicate that the average size is approximately 3800 watts, which corresponds to an EER of approximately seven. For room air conditioners, the average sales weighted size is about 10,000 BTU/hr with an EER of six BTU/hr/watt (Ref. 9, App. A). Dividing the air conditioner size by its EER yields an estimate of 1670 watts for the present power consumption of a typical room air conditioner.*

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*We have not had the opportunity to incorporate into our analysis the recent changes in state code requiring increased EER for air conditioning. These increases in air conditioning efficiency would tend to make our calculation of savings of energy and capacity too high. The yearly savings would scale by the ratio of the EER.

The estimates derived above are recorded in Table B-2. They have in turn been used to calculate capacity savings from reduced cooling load. To estimate capacity savings we need to make assumptions about when the heating and cooling demands fall on the daily and annual load curves. Residential space heating occurs during evening and night time hours during the winter. This does not presently correspond to the time at which the annual peak occurs; consequently we assume there will be no capacity savings attributable to the energy savings in space heating.

Residential cooling occurs during the summer peak; consequently the reduced cooling loads in passive solar houses will result in both energy and new generating capacity savings. For the calculation of capacity savings, we assume that the daily distribution of the number of air conditioners in use during the peak hours (approximately 1 PM to 7 PM) is flat. A study of air conditioning demand in the Fresno area gives a load distribution curve that shows less than 15 percent variation during this period.[12] Since the system peak occurs at approximately 2 PM, a change in the air conditioning load will directly reduce the system peak. In addition, there is evidence that little, if any, significant oversizing of air conditioning units exists;[12] therefore on very hot days no cycling of the unit is likely to occur. Our calculation of peak savings assumes a 60 percent reduction in the required cooling unit size only, and does not include air conditioner cycling during the peak hours.

We assume the air conditioning capacity savings will, in turn, reduce the number of gas turbines and pumped storage units required. Our calculation takes into account transmission losses, a forced outage rate for gas turbines, air conditioning saturation, and projected housing construction rates. We estimate a total incremental reduction in peaking capacity at 280 megawatts per year and a total annual incremental energy savings of 144 million kilowatt hours per year. These results are derived in Table B-2. Using the power plant and fuel characteristics shown in Table A-1, the incremental fuel savings resulting from the reduction in gas turbine requirements is 310,000 barrels of distillate oil per year.

Our calculations thus far have been presented in annual increments. It is also interesting to note the cumulative savings, as they will form the basis of our comparisons between investment strategies involving

Table B-2

Annual Incremental Energy and Capacity Savings from Passive Solar Housing

Housing Type	End Use	Unit Size or Unit Energy Consumption[a]	Savings Factor[b]	Savings Per Unit at End Use	Loss Factor[c]	Use Factor[d]	Number of Units X 10^3 installed annually[e]	Savings Statewide
Single Family	Gas heat	46.5×10^6 BTU	.6	27.9×10^6 BTU	1.08	1	69.7	2.1×10^{12} BTU
	Elec.heat	7650 kwh	.6	4590 kwh	1.1	1	32.8	166×10^6 kwh
	Central A/C, energy	2640 kwh	.6	1580 kwh	1.1	1	51.3	89×10^6 kwh
	Central A/C, capacity	3800 W	.6	2280 W	1.3	.85	51.3	130 MW
	Room A/C, energy	920 kwh	.6	550 kwh	1.1	1	10.3	6×10^6 kwh
	Room A/C, capacity	1670 W	.6	1000 W	1.3	.85	10.3	10 MW
Multifamily	Gas heat	22×10^6 BTU	.6	13.2×10^6 BTU	1.08	1	69.7	1.0×10^{12} BTU
	Elec. heat	3360 kwh	.6	2020 kwh	1.1	1	32.8	73×10^6 kwh
	Central A/C, energy	1260 kwh	.6	760 kwh	1.1	1	51.3	43×10^6 kwh
	Central A/C, capacity	3800 W	.6	2280 W	1.3	.85	51.3	130 MW
	Room A/C, energy	920 kwh	.6	550 kwh	1.1	1	10.3	6×10^6 kwh
	Room A/C, capacity	1670 W	.6	100 W	1.3	.85	10.3	10 MW

TOTAL SAVINGS:

Gas: 3.1×10^{12} BTU

Elec.Energy:
Heating: 239×10^6 kwh
A/C: 144×10^6 kwh
Capacity: 280 MW

a. See text.

b. An assumed 60 percent savings factor was applied to all end use categories.

c. The loss factor accounts for transmission losses of gas and electricity. The estimate for gas losses is from Robert A. Filip, Testamony before CERCDC, Southern California Gas Company, June 23, 1976. For the capacity savings calculations, the 1.1 transmission loss was corrected for an assumed forced outage rate for gas turbines of 0.15. The correction factor by which the transmission loss was multiplied is $(1 - 0.15)^{-1}$, yielding 1.3.

d. The capacity savings are adjusted for an 85 percent use factor that accounts for vacations or other absences during the cooling hours.

e. We assume 68 percent of the new houses constructed will use natural gas and 32 percent will use electricity for space heating. We also assume that 50 percent of the new houses constructed will have central air conditioning, and another ten percent will have room air conditioners.

energy conservation on the one hand and power plant construction on the other. Over a twenty-year period, we estimate a peak load power plant capacity savings of 5600 megawatts, and an integrated energy savings for gas of nearly 0.6 X 10^{15} BTU and for electricity of 77 billion kilowatt hours. Assuming an average heat rate of 10,000 BTU/kwh, the cumulative electricity savings translates to 133 million barrels of crude oil at the end of twenty years. This is roughly 25 percent of the present annual oil consumption in California.

DIRECT MATERIAL REQUIREMENTS

Passive solar housing requires additional materials for wall and ceiling insulation and for double glazing beyond those used to comply with present state codes. We calculate the materials needed to upgrade the wall and ceiling insulation from R-11 to R-19 (currently state code[18]) to R-19 and R-30 respectively. We also estimate the additional glass and other materials used to manufacture the double glazed window units needed. The walls will be constructed with 2 X 6 studs on 24 inch centers to accommodate the thicker wall insulation; but we expect there will be no additional lumber needed.*

Glass and insulation are the primary materials that will be increased in the construction of a passive solar house. However, other materials also may be important, such as those used to increase thermal mass or to provide shading. The major difficulty in estimating the materials used for these purposes lies in predicting the amounts needed and the manner in which they will be combined. For example, shading of windows

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*In 2 X 4 stud construction studs are usually placed on center at 16 inches; in 2 X 6 stud construction they are centered at 24 inches. For every four feet of wall, one less stud is needed in 2 X 6 construction (see Ref.1). For the average single family dwelling of 1450 ft^2 at most two 2 X 4 studs would be saved by using 2 X 6 stud construction. Because the difference is not large, it was assumed that no significant change would occur in the amount of wood required. The difference in lumber cost is expected to be insignificant if the lumber industry retools and accelerates output of 2 X 6 studs for use as the standard construction stud material.

can be accomplished by overhangs, louvered sun shades, draperies, special glazing, awnings, shutters, and vegetation. Since the choice will be determined by personal preferences, availability and costs, it is not possible to estimate these material requirements.

The calculation of additional insulation in Table B-3 is based on wholesale prices of $\$0.069/ft^2$ for R-11, $\$0.119/ft^2$ for R-19 and $\$0.188/ft^2$ for R-30.[17] The incremental demand for insulation by housing type (Table B-4) was calculated by year for the next twenty years using the CERCDC estimates of housing construction rates. The additional materials cost of a 4' X 5' double glazed window unit is presented in Table B-4. The cost per dwelling of each component shown in Table B-5 is calculated by multiplying the cost per window unit by the number of window units per dwelling (14.5 for single family and 44 for multifamily). The total annual costs are also shown in Table B-5.

We have assumed that builders and owners of passive solar houses will on the average install smaller air conditioners and space heaters. The statewide average savings in first costs for space heating and cooling are shown in Table B-6. The cost figures are retail prices taken from the Sears catalog.[19] For space heating we estimated a 60 percent savings in furnace size translates to a $60 savings in single family dwellings and a $100 savings in a four unit multifamily dwelling.

For air conditioners, the calculation requires more assumptions. In some areas passive solar houses will obviate the need for air conditioners, while in others, smaller units will be needed. One problem is that small central air conditioners ($\sim$1 ton) are not currently manufactured, thus we cannot estimate the savings due to installing smaller central units. For purposes of calculation we assume that 20 percent of passive solar dwellings would have central air conditioners of currently installed sizes. The expected saturation for current code houses is 50 percent. Thus we assume there will be 60 percent fewer central air conditioners installed. In practice we expect this 60 percent reduction to result from a combination of reduced unit size and fewer installed units. This amounts to a savings of $800 in a single family dwelling and $960 in a four unit multifamily dwelling. We further assume that in the ten percent of the dwelling units that are expected to have room air conditioners, the capacity will be 60 percent smaller, resulting in a savings of $160 per unit.

Table B-3

Costs of Additional Insulation[a]
(in 1976 $)

	Present State Code[b]		Solar Tempered Dwellings	
Single Family Dwelling	R-11 walls (926 sq.ft.)	$ 63.89	R-19 walls (926 sq.ft.)	$110.19
	R-19 ceiling (1450 sq.ft.	$172.55	R-30 ceiling (1450 sq.ft.)	$272.60
	Total	$236.44	Total	$382.79
	Increase in insulation cost for solar tempered dwelling	$146.35		
Multiple Family Dwelling	R-11 walls (2128 sq.ft.)	$146.83	R-19 walls (2128 sq.ft.)	$253.23
	R-19 ceiling (2200 sq.ft.)	$261.80	R-30 ceiling (2200 sq.ft.)	$413.60
	Total	$408.63	Total	$666.83
	Increase in insulation cost for solar tempered dwelling = $64.55 per unit	$258.20		

[a]All costs calculated using the following quoted wholesale prices (1976 dollars): $69.00/1000 sq.ft. R-11; $119.00/1000 sq.ft. R-19; and an estimated price of $188.00/1000 sq.ft. R-30. (Confidential communication with private contractor.)

[b]Ref. 18.

Table B-4

Cost of Additional Material Components of Double Glazed Window Unit[a]
(in 1976 $)

Material	Use	Cost/unit[b]	Cost of 4'X5' window unit[b]
Glass[c]	Panes	22.5¢/sq.ft[d]	$4.50
Aluminum	Spacers (1/2")	.0039¢[e]/inch	.84
Polysulfide Compound	Sealant	.008¢[e]/inch	1.73
Polyisobutylene	Sealant	.002¢[e]/inch	.43
Silica gel (50%) and Molecular Sieve	Dessicant	.0038¢[e]/inch	.82
Zinc	Corner Keys (Gussett)	4¢/corner[e]	.16
Solder and Misc. Material	Sealant for Corners	.001¢[e]/inch	.22
		TOTAL	= $8.70

[a]Assumes unit is made of clear double strength glass and is sealed on all four sides.

[b]Producer's prices exludes labor and equipment overhead.

[c]One plate of clear double strength glass, 1/8" thick.

[d]Consensus from Libby Owen Ford and Pittsburgh Plate Glass Industries.

[e]Paul Thompson of Havlin-Witkin, Sacramento.

Table B-5

Passive Solar Housing
Summary of annual incremental costs
(in 1976 $)

Item	Sic Code	I-O Sector	Cost per dwelling: Single family	Cost per dwelling: Multi-family	Total annual costs (10^6): Single family	Total annual costs (10^6): Multi-family	Total annual costs (10^6): total
Insulation	3246	36.20	146.35	258.20	15.0	6.8	21.8
Window Units			126.15	382.80	13.1	10.0	23.1
Glass	3211	35.01	66.70	202.40	6.8	5.3	12.1
Aluminum	3361	38.11	12.18	36.96	1.2	1.0	2.2
Polysulfide Sealant	2822	28.02	25.09	76.12	2.6	2.0	4.6
Polyisobutylene	2821	28.01	6.24	18.92	0.7	0.5	1.2
Dessicant	2819	27.01	11.89	36.08	1.2	1.0	2.2
Zinc	3356	38.09	2.32	7.04	0.3	0.2	0.5
Solder and misc.	3356	38.09	3.19	9.68	0.3	0.3	0.6
Total Cost Per Dwelling			272.50	641.00			
Total Annual Cost							44.9

Table B-6

Cost Savings for Residential Space Heating and Cooling

Space Cooling	Current Cost Per Dwelling[a]	Future Cost Per Dwelling[a]	Savings Per Unit	Dwelling Units[b] (Per Year)	Total Savings 10^6 $
Room	$350	$190	160	20,500	3.3
Central - SF	800	0	800	30,750	24.6
Central - MF	960	0	240	30,750	7.4
					35.3
Space Heating					
Single Family	305	245	60	102,500	6.1
Multifamily	450	350	25	102,500	2.6
					8.7
Total Heating and Cooling (Annual)					44.0

[a]Cost data from Ref. 19.

[b]See footnote e Table B-2.

The total savings in first cost for space heating and cooling amounts to $44 million per year. The corresponding wholesale price is $41 million which is to be compared to an additional wholesale annual cost of $45 million for glazing and insulation. Since these costs are comparable, there will be little if any net cost increase in constructing passive solar dwellings. These calculations ignore any increase in materials requirements that may result from adding adequate shading and thermal mass.

DIRECT MANPOWER REQUIREMENTS

No additional direct manpower requirement was calculated for construction of passive solar houses. There may be some additional on-site labor for additional thermal mass and shading. We have not quantified this because the methods for adding these components are highly variable. Wall and ceiling insulation are required by present state code. We assume that installation of thicker layers of insulation will require negligible, if any, extra effort. Since most double glazed window units are prefabricated, no labor will be required beyond that already used to install single glazed units. Finally, no significant change is anticipated in the amount of labor needed for framing or for installing smaller heating and cooling units. Indirect manpower requirements will increase because of the increased requirements for glass and insulation. These are estimated and discussed in our analysis of the third scenario.

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APPENDIX C

DELAMPING IN COMMERCIAL BUILDINGS*

INTRODUCTION

The delamping program we consider entails the removal of a percentage of fluorescent light bulbs from the installed fixtures and the replacement of them by Phantom™ tubes.** This would result in a uniformly lower level of lighting. We assume a delamping program in office buildings, retail stores and schools that would take place in California over a five-year period.

First we estimate the potential power and energy savings that would result from lower lighting levels in each building type. We then calculate the number of Phantom™ tubes by building type required for this reduction. Next, we translate the power and energy savings into capacity and fuel savings. Finally, we discuss the material and manpower needed to manufacture and install the Phantom™ tubes.

POTENTIAL POWER AND ENERGY SAVINGS

Office Buildings

The average lighting level of new office buildings has increased over the past twenty years. The potential savings therefore depend on the age of the building. The age distribution of average national lighting levels shown in Table C-1 comes from Ross and Baruzzini.[4] Since the lighting levels in California are generally higher than the national

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*Data collection and calculations for this section were performed by Edward Kahn of the LBL Energy Conservation Group as part of the conservation research and data collection project funded by CERCDC.

**Most lighting fixtures in office buildings are series-wired multiple lamp fixtures. To reduce the lighting level and maintain uniform lighting throughout the building, two options are available: 1) rewire the fixture to take a single tube ballast; 2) install a Phantom™ tube in place of the tube removed. The Phantom™ tube connects a capacitor across the contacts and allows the remaining tube to light. Efficiency is maintained but the total lighting level drops to 30 percent of the original level of the two-tube fixture.

average, we scaled up these data to get the lighting distribution in California. The average lighting power demand in the state is 3.56 w/ft^2 as compared to the national figure of 2.72 w/ft^2. Thus we scale the power demand by 1.31. Similarly, the in-state energy demand is 1.48 times the national value (10.5 vs. 7.1 kwh/ft^2). The average annual operating hours in Table C-1 are calculated by dividing energy by power demand.

We take as a goal a reduction in lighting level to 2 w/ft^2 as recommended in Ref. 4. The savings in lighting power is shown in col.1 of Table C-2. Assuming the lighting hours will not change, we calculate the potential lighting energy savings. Multiplying these by the existing commercial floor space for each age class[2] gives a total power savings of 740×10^3 kw and a total energy savings of 2.67×10^9 kwh. The number of Phantom™ tubes required, based on a savings of 63 watts per tube, is 11.8 million.

So far we have ignored the commercial floor space that is more than 20 years old which amounts to 38 percent of the total.[3] These older office buildings have, on the average, a lower lighting level than the new ones. Furthermore, a larger but unknown percentage are lit with incandescent bulbs. We have estimated that the delamping potential for these buildings is at most 2.5 million tubes. Because we do not know the breakdown between incandescent and fluorescent fixtures for this age class, and since the tubes required would be less than five percent of those in the total delamping program, we have not included them in our calculations.

Retail Stores

To estimate potential demand savings for retail stores, we rely upon the A.D. Little estimates[1] of the impact of the ASHRAE 90-75 standard on new construction. This is a reasonable proxy for the distribution of lighting levels in the existing stock because of the role that lighting plays in marketing. Retail merchants view lighting as an important marketing tool. Therefore recent construction practice is not likely to be very different than the general lighting level in the stock of retail buildings, and consequently there is a uniform distribution of

Table C-1

Present Power Demand and Lighting Energy
Office Buildings

Building Age (Years)	National			California		
	Lighting Power Demand (w/ft^2)	Annual Lighting Energy (kwh/ft^2)	Average Lighting Hours	Lighting Power Demand (w/ft^2)	Annual Lighting Energy (khw/ft^2)	Average Lighting Hours
0-4	3.43	11.5	3350	4.49	17.0	3790
5-9	3.26	10.1	3100	4.27	14.9	3500
10-14	2.83	9.5	3360	3.70	14.0	3790
15-19	2.64	7.1	2690	3.46	10.5	3040

Table C-2

Potential Power and Energy Savings
Office Buildings

Building Age (Years)	Power Savings (w/ft^2)	Energy Savings (kwh/ft^2)	Office Building Floorspace (10^6 ft^2)	Total Power Savings (10^3 kw)	Total Energy Savings (10^9kwh)	Tubes Required (10^6)
0-4	2.49	9.4	107.9	270	1.01	4.3
5-9	2.27	7.9	110.7	250	0.87	4.0
10-14	1.70	6.4	87.8	150	0.56	2.4
15-19	1.46	4.4	50.8	70	0.22	1.1
Total				740	2.67	11.8

lighting levels with respect to building age. A.D. Little estimates that 8.24 kwh/ft^2 can be saved annually in retail lighting. Assuming the typical store stays lit for 3500 hours annually, the lighting energy can therefore be reduced by 2.35 watts/ft^2. It is unlikely that this estimate will apply to 100 percent of the stock of retail stores because not all retail stores will be lit to the levels of stores constructed today. Since we expect the variation of lighting among retail stores to be less than that for office buildings, the lower bound on the applicable stock should be given by the estimate for office buildings (62 percent of the stock). From working with the data our intuitive feeling is that something more than 62 percent is the appropriate figure. We have chosen the figure 85 percent. Obviously, this assumption affects our results. Based on 85 percent of the estimate of retail floorspace in Ref. 3 of 820 million square feet, and a savings of 2.35 w/ft^2, we calculate total power savings of 1638 X 10^3 kw. Converting this into Phantom™ tubes required, at a savings of 63 watts per tube, we calculate 26 million tubes are required. The energy saved is 5.73 X 10^9 kwh, based on 3500 hours per year of lighting.

Schools

Using the A.D. Little estimates[1] of lighting energy than can be saved in school buildings, we derived an estimate of 2 kwh/ft^2 annually. Assuming 2000 hours of lighting annually, this means about 1 w/ft^2 of demand can be eliminated. The estimate of school floorspace, given in Ref. 3, of 570 million square feet, yields a total power savings of 570 X 10^3 kw. Nine million Phantom™ tubes are required. The energy saved is 1.14 X 10^9 kwh.

Additional Energy Savings

Reduced lighting levels reduce the heat load of a building. This leads to a decrease in the energy and capacity required to cool in the summer. It also leads to an increase in the energy required to heat during the winter. A rough rule of thumb is that energy requirements

for cooling are reduced by 50 percent of the reduction in lighting level, and those for heating are increased by 33 percent. Thus there may be an additional net energy savings attributable to delamping.

However, an estimate of these savings requires data on the fraction of commercial floor space that is air conditioned and on the efficiency of the air conditioners, both of which are presently not available. Therefore, we have not calculated the additional energy and capacity savings from reduced space cooling requirements which might be expected.

FUEL AND CAPACITY SAVINGS

The demand for commercial lighting is nearly constant throughout the year and occurs primarily during the daytime and evening hours. We assumed that this demand is satisfied by base and intermediate load power plants. The reduction in capacity will therefore take place by cancelling or delaying base load power plants. Any additional energy reduction not accounted for by decreasing capacity is assumed to result from a decrease in the amount of residual fuel oil burned.

Base load capacity savings due to the delamping program are calculated directly from the power demand in office buildings and retail stores. Since schools are not in use for the full year, we have not included their power demand in our calculation of base load capacity reduction. The capacity reduction is the power demand multiplied by 1.1 to remove transmission losses and divided by (1 - forced outage rate) which is taken to be 0.15. The results, shown in Table C-3, total 3080 MW at the completion of the five-year delamping program.

Annual fuel savings, shown in the last column of Table C-3 are derived from the energy demand savings multiplied by 1.1 to correct for transmission losses and by 10,000 BTU/kwh, the assumed heat rate. The total savings are approximately 105 X 10^{12} BTU. This result may differ slightly from the savings calculated in scenario 3 because the heat rates used there are tied to the particular type of capacity obviated.

Table C-3

Summary of Savings and Requirements from Delamping

	Phantom™ Tubes Required (Millions)	Energy Demand Reduction (10^9 kwh)	Power Demand Reduction (10^3 kw)	Capacity Reduction (MW)	Annual Fuel Savings[a] (10^{12} BTU)
Office Buildings	11.8	2.67	740	960	29
Retail Stores	26.0	5.73	1640	2120	63
Schools	9.0	1.14	570	0[b]	13
Total	46.8	9.54	2950	3080	105

a. Annual fuel savings after completion of the five-year program.

b. Schools are not included in base load capacity reduction because they are not in use throughout the year.

DIRECT MATERIAL AND MANPOWER REQUIREMENTS

The Phantom™ tubes consists of an uncoated fluorescent tube with a capacitor connected from one end to the other. Presently the components are purchased separately and assembled by hand. Assembly requires soldering and gluing. It appears likely that production of Phantom™ tubes for a large-scale delamping program would be mass produced, perhaps by firms currently producing fluorescent bulbs. In this case, Phantom™ tube production would be substituted for fluorescent tube production to the extent required by the delamping program. Under these circumstances, as a first approximation, there would be no appreciable change in employment for production. The materials are similar for both products; therefore there would be no appreciable change in income to other sectors as production shifts from fluorescent to Phantom™ tubes. This statement does not hold for a few inputs unique to each product. If we assume that the installation of Phantom™ tubes would be done during routine replacement of fluorescent tubes, there would be no added employment impact for installation. We will use these assumptions for our calculations of the indirect impacts in the third scenario.

If the Phantom™ tubes are not mass produced, which may be a less likely case, the wholesale price would be approximately $5.10/tube in large lots. This amounts to approximately 240 million dollars for the statewide delamping program, of which 43 million would be for direct labor. Installation would require an additional 30 million dollars if not undertaken during routine replacement. The details of these calculations are given in Tables C-4, C-5, and C-6.

Table C-4

Direct Material Inputs for Phantom™ Tubes

Item	SIC Code 1972	Input-Output Sector	Cost/tube[a] $(1976)	Cost of Program 10^3 $(1976)
Glue[b]	2891	24.04	.0032	150
Wire[c]	3357	38.10	.057	2,670
Bipin Connectors[d]	3643	55.03	.067	3,150
Glass Envelopes[e]	3229	35.01	.160	7,490
Capacitors[f]	3629	53.08	.856	40,000
Total[g]			1.143	53,500
Wholesale Price[h]			5.12	240,000

a. Includes shipping cost.

b. Hot melt glue suitable for glass and aluminum at $3.17/lb - estimated to be good for 1000 tubes. Price from Cal-State Distributors: Cold and Hot Melt Glue Systems, 1628 E. 14th St., Oakland.

c. Wire at $13.34/100 ft; 4 ft/tube. Beldon: 20 gauge; 7 strand. PUC jacket tinned. Depending on the type of wire used the price of this item could vary by a factor of two.

d. Cost $29.70/thousand. Shipping cost to west coast: $4.00/1000. Source: G.E. Lamp Products Division.

e. Cost for envelopes; 4 ft. $65.65/1000, 8 ft. $124.75/1000, Other $100.00/1000. Current mix of sales for Phantom™ tubes 70 percent 4 ft., 18 percent 8 ft., and 12 percent other. Shipping costs to west coast: $60-100/1000 tubes depending upon size and weight. Source: G.E. Lamp Products Division.

f. Assumes 90 percent of sales are Sprague 277-P or equivalent at $640/1000. Approximately 10 percent of sales with capacitor costing 4 times as much. Sources: William J. Purdy Co. and Development Sciences, Inc.

g. The solder input is assumed to be negligible. Also, there is no allowance for breakage or theft.

h. Cost for sales in large (20,000) lots. Price for medium size lots (1000) is $6.25/tube; small lots cost more than $7/tube. Source: Developmental Sciences, Inc. Cost in table includes 12¢/tube for shipping.

Table C-5

Direct Labor Inputs for Phantom™ Tube Production

Type of Labor	Wage $/hr	Man-hrs/ tube	Cost/ tube $(1976)	State delamping program Cost $10^3$$ (1976)	Labor man-yrs[a]
Assemblers (unskilled)	2.50	0.23	.57	26,700	5380
Supervisors	6.50	0.03	.18	8,400	700
Shipping-Packing Receiving-Secretarial	3.50	0.02	.07	3,300	470
Quality Control Inspectors	6.50	0.01	.09	4,200	230
Total (on average)	3.16	0.29	.92	43,000	6800
Installers	5.80[b]	0.11	.64	30,000	2570

a. Assumes 50-week work year; 2 weeks paid vacation.

b. Assumes a team of two persons, consisting of an apprentice electrician at $6.50/hr and a laborer at $4.50/hr.

Table C-6

Summary of Direct Inputs

	Cost/tube $(1976)	Cost of Program 10^3 $(1976)
Labor	0.916	42,900
Materials	1.143	53,500
Capital[a]	0.008	400
Rent[b]	0.076	3,600
Shipping[c]	0.120	5,600
Sub-total	2.263	105,900
Wholesale Price[d]	5.12	240,000
Installation	.64	30,000
Price + Installation	5.76	270,000

a. Assumes a five-year program, the minimum amount of time estimated by the manufacturers to amortize investment in machinery and air conditioning equipment in leased floor space. An estimated $100,000 capital is needed to product 2.5 X 10^6 tubes/year, so in five years this capital can produce 12.5 million tubes. Capital expense estimate from Developmental Sciences, Inc.

b. 100,000 ft^2 floor space is required for production of 2.5 X 10^6 tubes/year. The cost is approximately 16¢/ft^2/month assuming that one-half of the floor space is air conditioned.

c. $12-15 shipping/100 tubes. Costs lower for larger orders. Source: Developmental Sciences, Inc.

d. See footnote h, Table C-4.

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APPENDIX D

RETROFIT CEILING INSULATION

INTRODUCTION

The retrofit insulation program is designed to upgrade the ceiling insulation to an R-19 standard in approximately 4.5 million existing residences. Increased ceiling insulation serves to retard heat loss through the ceiling during the winter, and to limit heat gain through the ceiling during the summer. We decided to limit our estimates to ceiling insulation because it appears most likely to be retrofit. The basic operation involves unrolling insulation batts or blowing loose insulation into the attic. Obviously additional energy savings are possible by retrofit insulating walls also, but this is a more difficult operation.

While the central concepts regarding retrofit ceiling insulation are simple, the calculations of the energy and capacity savings, and material and manpower requirements are not. Factors that can affect the potential energy savings include the number of dwellings that can be retrofit, the amount of insulation in the existing housing stock, the percentage of this stock with open beamed ceilings or flat roofs (and therefore less likely to be insulated), and the quality of the building materials, glazing, and weather stripping in the present stock. This information is not available. Therefore we have had to make estimates based on very small samples and extensive assumptions. Our calculations should be interpreted as rough estimates that at best indicate the order of magnitude of the savings. Because of the imprecision involved, we have tried to be conservative in our estimates.

MATERIAL AND MANPOWER REQUIREMENTS*

For the calculation of the materials and labor requirements, we assume the housing stock can be categorized into three types: single family, two unit multifamily, and mobile. We have estimated the number of dwellings with gas heat or electrical heat for each type and their average roof areas; these data are shown in Table D-1.

The calculation of the amount of insulation required is summarized in Table D-1. Of the existing single family houses, about 2.3 million are gas heated.[1] There are an additional 245 thousand electrically heated single family homes that are estimated to have an average insulation level of R-7.[2] To bring all these single family dwellings up to the R-19 standard would require 3.4×10^9 ft^2 of insulation. Similarly, we estimate there are 1.2 million gas heated[3] and 480 thousand electrically heated[2] multifamily dwellings that are not fully insulated. We assume that due to structural variations, such as flat roof construction, only half of them are insulatable. This gives us about 0.5×10^9 ft^2 of roof area to be insulated. There are also 300 thousand uninsulated mobile homes in the state,[4] most of which are gas heated. This represents an additional 0.3×10^9 ft^2 that can be insulated. Thus a total of 4×10^9 ft^2 of R-19 equivalent insulation will be required for this program.

The current wholesale price of R-19 insulation is $0.12 per square foot and the installed price is $0.22 per square foot.[5] This gives a direct materials cost of $480 million and a direct increase in value added of $400 million. We estimate that 8000 man-years of labor will be needed for installation.[6] The insulation used will be either mineral wool or fiberglas which are the principal outputs of the mineral wool industry (SIC code 3246). Using data from the 1972 Census of Manufactures,[7] we estimate the number of workers needed to produce the insulation. It requires 17,500 employees to produce $730 million worth of

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*Data collection and calculations for this section were performed by Robert Clear of the LBL Energy Conservation Group as part of the conservation research and data collection project funded by CERCDC.

Table D-1

Requirements for Retrofit Ceiling Insulation*

	Single Family	Multi-family	Mobile	Total
Number of Dwellings[a] (millions)	4.8	2.4	0.4	7.5
Gas Heated				
Number uninsulated (millions)	2.3[b]	1.2[c]	0.3[d]	∿4.0
Ceiling area per unit (ft^2)	1450[e]	550[f]	1100[g]	---
Insulatable area[h] (10^9 ft^2)	3.2	0.3	0.3	3.8
Electrically Heated				
Number of units (millions)	0.245	0.48	--[i]	0.73
Ceiling area per unit (ft^2)	1450[e]	550[f]	--	---
Insulatable area[h] (10^9 ft^2)	0.4	0.3	--	0.7
Area of R-19 equivalent insulation (10^9 ft^2)[j]	0.2	0.17	--	0.4
Total Area of R-19 Equivalent Insulation (10^9 ft^2)	3.4	0.47	0.3	∿4.0

*Based on 1975 data.

a. Reference 2

b. Reference 1

c. Reference 3

d. Reference 4

e. Area of a "typical" single family house being use in the TWOZONE program.

f. Roof area for a "typical" two story multifamily structure containing two units is 1100 ft^2.

g. Calculated from average lengths and widths in a mobile home park residents survey. See Ref. 9.

h. We have assumed that 95 percent of all single family and mobile units have insulatable ceilings. A much smaller fraction of multifamily dwellings are insulatable to R-19; we assume this fraction to be approximately 0.5.

i. Mobile units are excluded because of lack of data.

j. We assume that the average insulation in electrically heated homes, presently is R-7, and the desired insulation level is R-19. Therefore the total amount of R-19 equivalent insulation is derived by multiplying the insulatable area by 12/19.

insulation at a producer's price of \$0.06 per square foot. This amounts to about 1500 employees per 10^9 ft^2 of insulation produced, or a total of 6000 employees needed for the full program. In Table D-2 we break this total down by skill. There are additional indirect manpower and materials needed to produce the materials used by the mineral wool sector. These are calculated using the input-output model described in Appendix A.

Energy Savings*

We have estimated the energy savings from the retrofit insulation program for both space heating and cooling. The cooling estimates have been done for single-family housing only. Table D-3 displays the data we have used in these calculations. The first column shows the number N_i of dwelling units of each type with gas heat, electric heat, central air conditioning, or room air conditioning. The fractions, f_j of each housing type with a given level of insulation (R-0, R-7 or R-19) are shown in the next three columns. An estimate M_i of the fraction of each type that can be retrofit insulated to R-19 is indicated next.

We have used the program TWOZONE[8] to estimate the energy consumption E_{ij} of each end use as a function of housing type and amount of insulation. These calculations have been normalized to aggregate energy consumption data reported by the utilities as follows:

$$E'_{ij} = E_{ij} \cdot \frac{E_j(\text{utility})}{\sum_{ij} f_i \cdot f_j \cdot E_{ij}} , \qquad \text{(D-1)}$$

where the indices i and j denote housing type and level of insulation, respectively, E(utility) is the average energy consumption for the device provided by the utilities, and f_i and f_j are the fraction of housing type and degree of insulation, respectively. The resulting energy consumption by device E'_{ij} for each housing type and insulation level is

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*Data collection and calculations for this section were performed by Robert Clear of the LBL Conservation Group as part of the conservation research and data collection project funded by CERCDC.

Table D-2

Labor Requirements for Insulation Production and Installation

Classification	Percentage Breakdown	Employee-years to Meet Statewide Retrofit Insulation Program of 4 X 10^9 ft^2 Insulation
Manufacture		
Total	100	6000[a]
Production Workers[b,d]	82	4920
Machinists	34	2040
Packaging	20	1200
Warehouse-loaders	10	600
Quality Control Inspectors	5	300
Secretaries and Typists	5	300
Engineers and Managerial	5	300
Accountants	3	180
Other Workers Including Sales, General Administrative and Other Overhead	18	1080
Installation		
Installers[c]		8000

a. Calculated from Tables 1 and 3 of Ref. 7.

b. The percentage of workers in production (82%) is from Table 1 of Ref.7.

c. See Ref. 6.

d. The breakdown of production workers by occupation was made by a plant engineer at The Willows Plant of Johns-Manville, Willows, California.

Table D-3

Annual Energy Savings from Retrofit Ceiling Insulation at Completion of the Program

Housing Type	End Use	N_i No. of Houses[a] Per End Use Category X 10^6	f_j Fraction with[c] Insulation R-			M_i Fraction[d] Insulatable	E'_{ij} Annual Unit Energy[e] Consumption Before Retrofit w/Insulation		S_{ij} Fractions Saved[f] by Insulating to R-19 from		T_i Loss Factor	E_i Energy Saved Statewide
			R-0	R-7	R-19		R-0	R-7	R-0	R-7		
Single Family	Gas heat	2.3[b]	1	0	0	.95	$100X10^6$BTU	--	.35	--	1.08	$82.6X10^{12}$BTU
	Elec. heat	.245	0	1	0	1		9040 kwh	--	.09	1.1	$220X10^6$kwh
	Central A/C	.689	.08	0	.92	1	3610 kwh	--	.182	--	1.1	$40X10^6$kwh
	Room A/C	1.119	.23	.77	0	1	1183 kwh	1046 kwh	.182	.075	1.1	$140X10^6$kwh
Multifamily	Gas heat	1.2[b]	1	0	0	.5	$45X10^6$BTU	--	.29	--	1.1	$8.7X10^{12}$BTU
	Elec. heat	.482	0	1	0	.5	--	3320 kwh	--	.05	1.1	$40X10^6$kwh
Mobile	Gas heat	.3[b]	1	0	0	.95	$75X10^6$BTU	--	.35	--	1.08	$8.1X10^{12}$BTU

Total Annual Savings

Natural Gas 99.4×10^{12} BTU

Electricity 440×10^6 kwh

a. Unless otherwise noted, these data are derived from saturations of heating and cooling equipment and housing stock by type shown in Tables 3 and 4 of Ref. 2.

b. See Table D-1 and accompanying footnotes.

c. We have assumed that, in general, gas heated houses have had no insulation installed (R-0) and electrically heated houses a small amount (R-7). With regards to air conditioning, we have used the results of Ref. 1, although it appears to us that these fractions overestimate the amount of insulation in both central and room air conditioned dwellings.

d. For both single family and mobile homes, the present stock is virtually all insulatable. As for multifamily residences, we assume that only half of this stock is capable of being retrofit with insulation.

e. The annual energy consumption per end use is from Ref. 2, disaggregated by insulation level using the results from TWOZONE. See text.

f. These savings estimates are from computer simulation runs using TWOZONE (Ref. 8).

shown in Table D-3. The fraction energy savings S_{ij} shown in the adjacent column is taken directly from the TWOZONE calculations.

The energy savings is then given by:

$$E_i(\text{savings}) = N_i \cdot f_j \cdot M_i \cdot E'_{ij} \cdot S_{ij} \cdot T_i \qquad \text{(D-2)}$$

where T_i corrects for transmission losses. The savings vary from nine percent to 35 percent depending upon the end use and the amount of insulation assumed before retrofit. The total estimated annual savings are 99 X 10^{12} BTU of natural gas and 440 X 10^6 kilowatt hours of electricity.

Two factors lead us to suspect our electricity savings estimates are conservative. First, the percentage of households that have room or central air conditioners and are uninsulated is based on a survey of one service area.[1] We suspect the estimate of uninsulated residential units is low because the survey is drawn from a sample of owner occupied homes. These are much more likely to be insulated. Thus there are probably more houses with little or no insulation than our estimates of f_j indicate. Second, our energy savings estimates from reduced cooling loads exclude multifamily and mobile homes.

We have estimated the impact of the retrofit insulation program on energy savings only. Although there probably is a capacity savings, it is extremely difficult to estimate. In the short run, the stock of air conditioners is fixed; therefore no change in capacity will occur, only the duration of use of the unit. But in the long run when air conditioning saturates and the stock begins to turn over, we suspect that smaller units may be purchased than would otherwise be the case if no insulation is retrofit. Thus in the long run we expect there are capacity savings that we have not attempted to quantify.

REFERENCES

1. Dressler Research Corp., "Ceiling Insulation Penetration and Attitude Research Report," DCW-2572-01, 1975 (Prepared by PG&E).

2. Lawrence Berkeley Laboratory, "Electrical Energy Consumption in California: Data Collection and Analysis," UCID-3847, July 1976.

3. Confidential communication with a private contractor.

4. Mobile homes prior to 1975 are assumed to be uninsulated.

5. Quote from a private contractor.

6. Fresno County Economic Opportunities Commission, "An Estimate of Jobs Created from a Statewide Insulation Program in California," undated.

7. U.S. Department of Commerce, Bureau of the Census, 1972 Census of Manufactures, MC72(P)-325-5 Mineral Wool.

8. TWOZONE is a computer program developed at LBL for calculating thermal loads in buildings. See Deane, E., and Rosenfeld, A.H., "A Model of Natural Energy Flows in Houses," LBL-4411, 1976 and Wall, L. et al., "Preliminary Results from an LBL Residential Computer Model."

APPENDIX E

ANALYSIS OF WIND POWER

The data used in this analysis of wind as an energy source have come from a Lockheed Aircraft mission analysis of wind for ERDA, of which we have a draft copy.[1] We have also had conversations with Michael Dubey of Lockheed, one of the authors of the report.

The Lockheed analysis concentrates on horizontally-mounted wind turbine generators (WTG), and looks at costs of delivered energy as a function of several parameters, including rotor diameter and average wind speed. We have chosen to use the analysis for a 105-meter rotor diameter, 4000KWe WTG, primarily because Lockheed has fully developed the data for that particular size. Although this is about a factor of three larger than the present 38 meter diameter WTG built by NASA/ERDA in Ohio, it is felt to be realistically achievable by Lockheed.[2]

This WTG has the lowest cost per unit of energy, although other sizes are not significantly more expensive. A summary of the capital costs, power rating at an optimal average wind velocity and energy costs are given in Table E-1. The capacity factors, according to the estimate by Lockheed in Fig. 4.2-13 of Ref. 1, do not vary significantly as a function of size for power ratings above 1000 KWe; these estimates vary only slightly with average wind velocities between 6 and 10 meters/sec.

The capital costs for one 4000 KWe WTG can be broken down into three main categories, the purchased equipment, the on-site construction (tower and pad), and on-site labor. These are shown in Table E-2. Lockheed's mission analysis also includes estimates of materials and manpower requirements for the direct and indirect requirements. These are shown in Tables E-3 (materials) and E-4 (manpower).

The estimate of labor required on-site of 8.7 man-years per unit is the year-by-year construction requirement. Lockheed estimates that one work team can build 10 units per year; each team would consist of 87 persons and require 0.1 year to build one WTG. A deployment rate of more than ten units per year will require more than one construction team, and will be reflected in the direct manpower requirements.

Table E-1

Summary of Size and Cost Characteristics of WTG*

Rotor Diam. (meters)	Power Rating[a] (MWe)	Capital Costs (10^6 $1975)	Energy Cost in ¢/KWe (1975) Average Wind Speed, meters/sec 6	7	8	9	10
60	1	0.72	3.8	2.8	2.2	1.9	1.7
79	2	1.20	3.1	2.3	1.8	1.6	1.5
93	3	1.71	2.8	2.1	1.7	1.5	1.4
105	4	2.24	2.8	2.1	1.7	1.5	1.4
122	6	3.27	2.8	2.2	1.8	1.6	1.5
			Average Capacity Factor[b]				
			.51	.54	.57 to .56	.58 to ∿.56	.59 to ∿.56

*Taken from Table 4.5-1, and Figs. 4.5-3 and 4.5-8 of Ref. 1.

a. Power rating at an optimal average wind speed of 7 meters/second.

b. Approximate extrapolations based on Fig. 4.2-13 of Ref. 1.

Table E-2

Capital Costs for 4000 KWe WTG, in 10^3 $

		1975 $[a]		3rd Quarter 1974[b]
Purchased Capital Equipment				
General Equipment[c]		365.4	325.2	
Gear Box	164.8			
Other Drive System Components	200.6			
Instrumentation and Controls[c]		160.4	142.8	
Turbine Controls	14.5			
Yaw Control	106.6			
Power Conditioning	39.3			
Electrical Equipment[c]		81.8	74.4	
Generator	81.8			
Miscellaneous[c]		1265.0	1125.9	
Blades	552.6			
Hub	559.1			
Platform	153.3			
Equipment Subtotal		1872.6		1668.3
Capital Resources for Construction				
Structural Products (tower, rebar)	137.0		126.1	
Concrete (foundation)	80.8		74.3	
Materials Subtotal		217.8		200.4
On-site Labor, Misc. Construction				
Site Preparation	22.1			
Transportation	32.2			
Assembly and Erection	90.8			
Labor Subtotal		145.1		137.9
Total Capital Costs[d]		2235.5		2006.5

a. Taken from Table 4.5-1, Ref. 1.

b. Deflators taken from the Survey of Current Business, Aug. 1975 and July 1976.

c. Categories from Bechtel Energy Supply Planning Model.

d. Total capital costs do not include owners' costs, such as land, transmission interties, etc.

Table E-3

Materials Requirements for 4000 KWe WTG, in 10^3 lbs.[a]

	Total weight	Carbon steel	Concrete	Aluminum alloy	Copper wire	Steel forgings	Steel castings	Steel alloy	Stainless Steel tubing	Stainless Steel sheet
Equipment										
Blade	36.5			31.0		5.5				
Hub	52.7					52.7				
Gear box	88.9					71.1	17.8			
Generator	21.0				8.4	8.4	4.2			
Rotor controls	0.5					0.2			0.1	0.2
Other transmission	51.3					20.5		30.8		
Yaw control	85.9				3.4	63.6	1.7	17.2		
Platform	192.5	192.5								
Subtotal	529.3	192.5		31.0	11.8	222.0	23.7	48.0	0.1	0.2
On-site Assembly										
Tower	188.8	188.8								
Foundation	1002.0	150.3	851.7							
Subtotal	1190.8	339.1	851.7							
Total[b]	1720.1	531.6[b]	851.7	31.0	11.8	222.0[b]	23.7[b]	48.0[b]	0.1[b]	0.2[b]

a. Taken from Table 8.2-1, Ref. 1.

b. Total steel - 825.6 X 10^3 lbs.

0 0 0 0 5 7 0 0 0 0 8 2

Table E-4

Manpower Requirements, 4000 KWe WTG (per unit)[a]

Labor Category	Man- hours	Man-years[b]
Manufacturing	142593	74.3
On-site Labor		
Site Preparation	2000	1.0
Transportation	951	0.5
Assembly and Erection	9494	4.9
Foundation	4444	2.3
On-site Subtotal	16889	8.7
TOTAL	159482	83.0

a. Taken from Table 8.5-1 of Ref. 1.

b. Using 1920 hrs/man-year.

Lockheed has estimated the yearly operations and maintenance as three percent of the capital cost. No further breakdown of this number was made; hence the total cost including manpower, materials, and spare parts is $60,000/year (3rd quarter, 1974).

One can assess the application of this particular WTG in California. At an annual average wind speed of 7 meters/sec (16 miles per hour), the average power density of the wind (proportional to the cube of the average velocity) is 400 watts/square meter. Data on annual wind velocity and frequency patterns are available for much of the U.S., including California, although most of these data are measured at heights of 10 meters. The WTG of interest here would have a ground-to-hub height of nearly 70 meters; corrections would have to be made for this additional height since there is a wind-sheer zone close to the earth's surface. This boundary layer is up to several hundred meters in thickness depending upon the exact nature of the terrain.

As a part of their Wind Energy Mission Analysis, Lockheed has gathered the available data on wind in the western states, and corrected these to 50 and 100 meter equivalent heights.[3] This survey shows, that for California, 10 areas out of approximately 80 reported had wind power densities exceeding 400 W/m^2, corrected to 50 m height, and 29 exceeded 400 W/m^2 at 100 m height. Lockheed has done more detailed wind energy measurements at several sites in California, all with potentials of greater than 400 W/m^2.[3]

One final parenthetical note. The major environmental consequence associated with at least a moderate level of WTG use is land use. The siting of an array of WTG's would have to be done in such a way as to prevent wind shadow effects. Lockheed estimates that ten rotor diameters is sufficient distance between each WTG. So for a total of 1 GWe (each with 105 meters rotor diameter, and rated at 4 MWe) sited in one array, the total land use is 263 square kilometers or approximately 100 square miles (64000 acres). This does not mean exclusive dedication of this land, although one would probably not want to allow permanent structures within the area of impact of the generator should it blow over (the radius of such as area is approximately equal to one-half the rotor diameter plus the tower height, or 2.9×10^4 m^2 per tower).

REFERENCES

1. Lockheed Aircraft Corporation, Wind Mission Analysis Study for ERDA, Draft report LR-27611, 1976. A summary of these results has also been published as: U. Coty and M. Dubey, "The High Potential of Wind as an Energy Resource," Lockheed-California Company, Second Annual Energy Symposium," Los Angeles Council of Engineers and Scientists, May 19, 1976.

2. M. Dubey, private communication, October 1976.

3. Lockheed Aircraft Corporation, "Maps of Usable Wind Energy by Region," Major Task Element #15 of the Wind Energy Mission Analysis, Draft report LR-27368-15, 1975.

APPENDIX F

SOLAR THERMAL-ELECTRIC POWER PLANTS

Research and development has been initiated in several areas on solar thermal-electric generation. ERDA has contracted with Honeywell, McDonnell-Douglas, and Martin Marietta to develop a 10 MW central receiver solar thermal pilot plant and with Boeing Corporation to develop heliostats. Sandia Laboratories, Livermore, California is the technical manager for these projects. An overall perspective on these ERDA projects was gained from a meeting held at Sandia Laboratories with Clifford Yokomizo.

Unfortunately, useful detailed cost information was unavailable. The major difficulties include the variety of designs each of which emphasize different building materials. For example, the heliostats designed by Honeywell have glass mirrors on a steel framework while Boeing's heliostats have a metallized plastic film on an aluminum frame which is enclosed in a protective dome. Another example is the difference in the actual components of the system; McDonnell-Douglas and Martin Marietta will use sensors to orient the reflective surfaces while Honeywell and Boeing plan a computer controlled system for orientation. Since the final design may come from any of these designs (to be chosen at a test facility) it is difficult to predict which of these technologies will be used. Consequently, costs are difficult to predict. Secondly, the costs involved in building the pilot test facilities and the demonstration plant are not representative of the costs of a commercial central-receiver solar thermal plant. Thus the cost estimates are too aggregated for use in the input-output table, incomplete, and not reliable as indicators of future actual costs of this type of plant.

The California Department of Water Resources has joined with Wismer & Becker, Contracting Engineers, in submitting a proposal to ERDA for the development and testing of component systems for a pilot solar-electric power plant. This proposal is based on a multi-module solar-electric plant concept developed by Professor Otto J.M. Smith of U.C. Berkeley. The multi-module solar collection concept provides an alternative to the central receiver solar energy collection concept. Our

efforts to obtain cost information on the level of detailed material and labor inputs have once again proved to be premature. The costing process used by the engineers at Wismer & Becker does not yield costs by the categories which would enable us to analyze the indirect impacts of producing the necessary bill of materials. On the other hand, the aggregate cost figures arrived at are built upon careful estimation techniques and appear to be reasonable when used with appropriate caution at the aggregate level. We have decided to use these estimates, appropriately deflated to 1974 values so as to be consistent with our data base. These data are presented in Table F-1. The multi-module design uses a 312-mirror array for each tower-receiver, and requires 1100 of these tower-mirror field modules for a 100 MW plant. The heat storage, turbine generator, and instrumentation are used by the entire plant.

On-site manpower costs have been derived from this table, assuming 80 percent of the installation cost is labor, and using a labor cost of $30,000/man-year. This gives 1070 X 10^3 man-hours or 557 man-years for each 100 MWe plant.

The Wismer & Becker report estimates annual operating and maintenance costs at 3 X 10^6 (1976 dollars) (2.3 X 10^6 1974 dollars). No further disaggregation of this cost is given; their estimate comes from operating and maintenance costs for coal-fired power plants.

A comparison of the Wismer & Becker estimates with other cost figures are shown in Table F-2. It is apparent that, while the estimates differ by up to a factor of 2, the Wismer & Becker values are just below the average of the estimates given.

The Electric Power Research Institute is currently sponsoring research directed at the problems of generating electricity from solar electric power plants early in 1977. We have verified by conversation that the estimates we have incorporated into our computations fall within, although at the low end, of the range of costs which they presently foresee.

Table F-1

Estimated Capital and Construction Cost of 100 MWe Solar-Electric Power Plant

	1976 dollars
Component Costs Per Module	
Mirror System: 312 X $180	$ 56,000
Towers 35 Meters High	4,000
Windowed Receiver	5,000
Subtotal	$ 65,000
Installation Cost Per Module	
Tower and Foundation	$ 2,000
Piping	2,000
Mirrors	3,000
Mirror Controls, Wiring	6,000
Roads	1,000
Adjustment and Checkout	5,000
Subtotal	$ 19,000
Total Cost Per Module	$ 84,000
100 MW Power Plant Cost	
1100 Modules at $84,000	$92,000,000
Heat Storage	4,000,000
Heat Exchangers, Turbine Generator, Transformer Switchyard	20,000,000
Central Computer System	1,000,000
Subtotal	$117,400,000
Interest During Construction	12,800,000
Total Capital and Interest Cost	$130,200,000

Source: Phase 1, Engineering Development and Testing of Component Systems for a Pilot Electric Power Plant — an unsolicited proposal submitted to ERDA by Wismer & Becker Contracting Engineers (Sacramento, CA) and the California Department of Water Resources, March 1976.

Table F-2

Estimates of Capital Costs for Solar Thermal Power Plants

	$/KWe (1974)[a]	Total Cost (millions)
Central Receiver, 100 MWe plant		
McDonnell-Douglas	1146	115
Project Independence	811	81
Aerospace Corporation	856	86
Jet Propulsion Laboratory		
no storage; dry cooling	1400	140
6 hr storage; wet cooling	1570	157
12 hr storage; wet cooling	2090	209
Distributed Collectors, 100 MWe plant		
Wismer & Becker[b]	1110	111
Jet Propulsion Laboratory		
steam, superheated, 6 hr storage, dry cooling	2415	242

a. Original cost data deflated to 1974 dollars using construction cost indices for commercial and factory buildings from the Survey of Current Business.

b. Designed by Otto Smith, Ph.D., Berkeley, California.

APPENDIX G

ENERGY GENERATION FROM MUNICIPAL SOLID WASTE

We have evaluated cost estimates for a variety of systems for converting municipal waste to energy. Direct combustion, conversion to fuel oil and to gas were considered. We examined the latter two in greatest detail; specifically, the Occidental Research Corporation's Flash Pyrolysis System[1] (FPS) that produces fuel oil,and the Union Carbide Corporation's Purox System[2] that produces fuel gas. Based on the following criteria we chose to incorporate the Purox System into our analysis: 1) pollutants; 2) fuel characteristics; 3) resource recovery; 4) energy efficiency; and 5) data availability. They are discussed in detail below.

POLLUTANTS

The Purox System produces fewer water and solid waste pollutants. It has no air effluents while FPS is expected to have particulate emissions which may exceed air pollution control standards in some California districts. For example, the Occidental Research Corporation anticipates SO_2 releases that exceed the Bay Area Air Pollution Control District limit of 300 ppm. (Scrubbers to remove the sulfur compounds represent a significant additional expense, e.g., 20 percent of the capital cost of a coal gasification plant.) The Purox System has one water effluent which will be treated on-site to make it acceptable for the municipal sewer system. The FPS produces three water effluents. According to Occidental Research one of these effluents (COD at 100,000 ppm) is the only potentially significant disposal problem. The solid waste produced by the FPS is not entirely inert and therefore must be landfilled at additional cost. The Purox System produces a granular glassy aggregate solid waste that is entirely inert and is saleable as a construction material for roads. The difficulty of the FPS regarding pollutants is that areas of population concentration, which provide the major reliable sources of solid waste, are also the areas in which pollution control regulations are the most stringent.

FUEL CHARACTERISTICS

The gas produced by the Purox System is a medium BTU fuel (375 BTU/cubic ft) that can be used directly in existing power plant systems that use natural gas (see Tables G-1 and G-2). The only modification necessary is an increase in the inlet burner size because a greater volume of the fuel gas relative to natural gas must be burned to obtain the same amount of heat. Although the gas must be pressurized before being transported to the power plant, the technology for this is well developed. In addition it is a clean burning fuel because potential pollutants have been scrubbed. The oil produced by the FPS requires special handling procedures. It is somewhat acidic and thus is corrosive to mild steel. Also it tends to polymerize in storage. This comparison of the fuel characteristics suggests that gas may be easier to market.

RESOURCE RECOVERY

The Purox System recovers 90 percent of the ferrous metals, but has no system for recovering either glass or aluminum. The FPS has three subsystems that recover ferrous metals, glass and aluminum. The front end separation and materials recovery represents a daily cost of $7100/ton in the FPS and $3400/ton in the Purox System. If consumer incentives, such as a bottle bill were adopted, the glass and aluminum content of the municipal solid waste would be greatly reduced and the FPS recovery subsystems would not be needed.

ENERGY EFFICIENCY

The Purox System is more energy efficient than the FPS. Estimates of the Purox energy efficiency range between 63 and 67 percent, while Occidental Research estimates that FPS will yield 33 percent net energy recovery (see Table G-3).

Table G-1

Fuel Gas Composition[a]

Constituents	Volume %
CO	47
H_2	33
CO_2	14
CH_4	4
C_2H_X	1
N_2	1
	100

a. Based on 7 X 10^6 BTU of gas per ton of refuse processed.

Table G-2

Comparison of Refuse Converter Fuel Gas with Natural Gas

	Refuse Converter Fuel Gas	Natural Gas[a]
Heating Value, BTU/SCF[b]	375	1000
Air Required for Combustion:[b]		
SCF Air/SCF Gas	2.4	9.5
SCF Air/Thousand BTU	8.0	9.5
Combustion Products:[c]		
SCF/Thousand BTU	9.4	10.5

*Source: Union Carbide

a. Assumed to be methane.

b. SCF - Standard Cubic Feet, measured at 60°F and 1 atmosphere.

c. Calculated for complete combustion with stoichiometric volume of air.

Table G-3

Energy Balance in a 2000 T/D Purox System

	Million BTU/hour	Percent	Million BTU/ton
Available Energy in Refuse[a]	832	100	9.5
Energy Losses in Conversion Process[b]	140	17	2.0
Energy Available in Fuel Gas	692	83	7.5
Fuel Gas Uses:			
Process Steam	32	4	
Building Heating	20	2	
Energy to Maintain Auxiliary Combusion Chamber at Operating Temperature	14	2	
Net Energy Available in Fuel Gas	616	75	

Source: Union Carbide

a. Based on a refuse heating value of 5000 BTU/lb.

b. Includes latent heat of moisture in refuse, sensible heat of fuel gas, heat content of molten slag and metal, and heat leak.

COST DATA

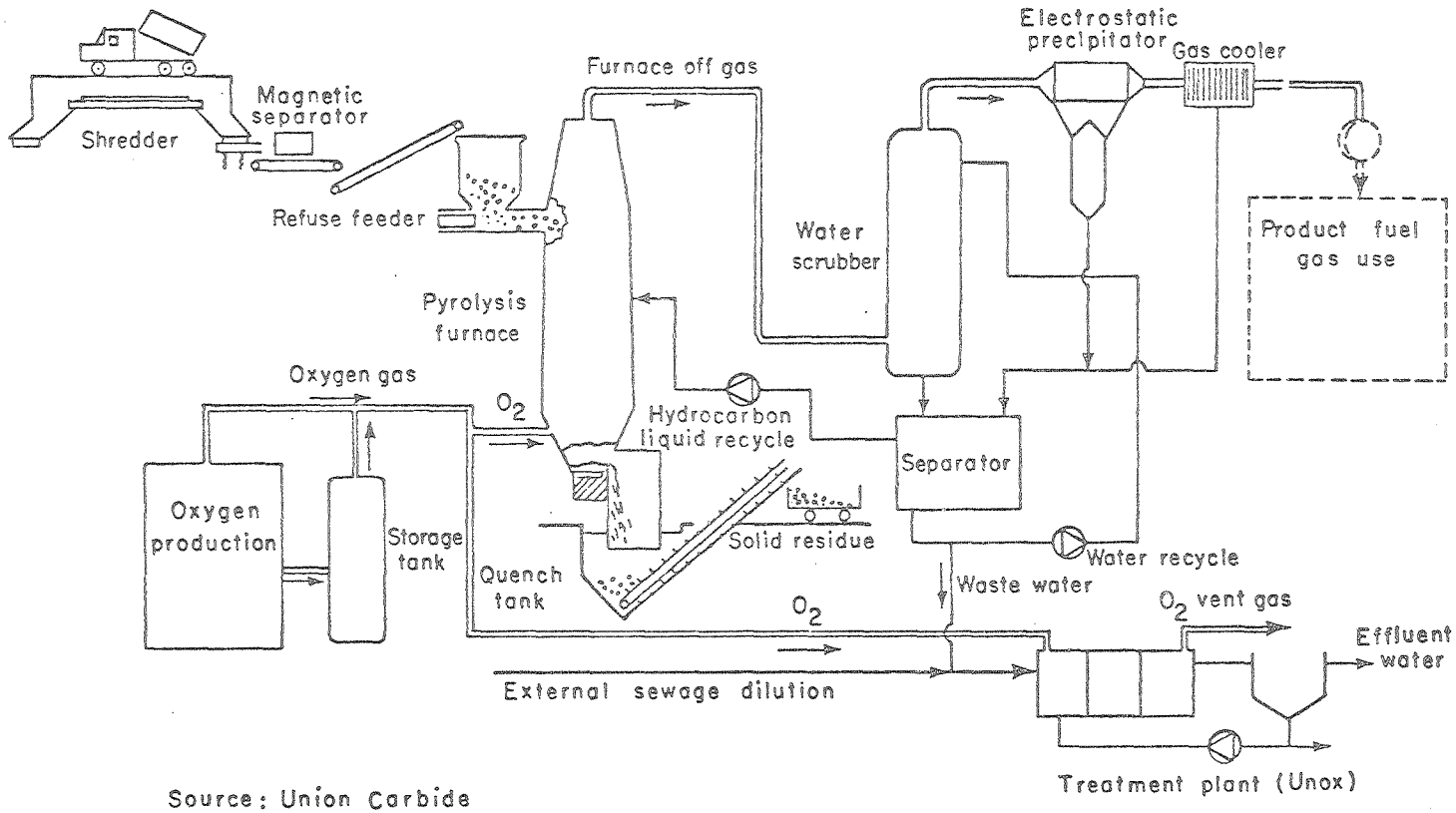
The Purox System has been demonstrated and is available commercially. A two-hundred ton/day facility operates in Charleston, West Virginia. A schematic of the system is presented in Fig. G-1.

We obtained cost information from Union Carbide for a 2000 ton/day facility. Because of the proprietary nature of the cost estimates, we were not supplied the working papers that show individual component costs in each SIC code. In Table G-4 the data are presented in a form compatible with the data in the Energy Supply Planning Model. This required scaling the data by a multiplier of 2.13 suggested by Union Carbode to approximate the cost of a 6000 ton/day facility. The total cost is 144 million 1974 dollars.

A 6000 ton/day plant can produce 1.53×10^{13} BTU of gas annually at the rate of 1.88×10^{9} BTU/hour. This annual level of energy is sufficient to power a 400 MW combined cycle power plant operating at 40 percent thermal efficiency with a capacity factor of 50 percent. However, the power plant consumes gas at a rate of 3.41×10^{9} BTU/hour which is higher than the Purox System's rate of production. Thus we assume that the facility contains a pressurized gas storage tank that permits gas consumption at this rate.

In the Energy Supply Planning Model a biomass unit includes a 6000 ton/day Purox plant supplying gas to a 400 MWe combined cycle power plant. The capital and operating cost data for the two plants were combined to represent this single unit. It was also assumed that the Purox plant would be built over the same time period that the combined cycle plant would be built. Operating costs for the Purox plant (three percent of capital investment) include maintenance and repair costs and labor costs but do not include capital writeoff, Purox system operating fee and other miscellaneous costs.

PUROX SYSTEM



Source: Union Carbide

Figure G-1

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Table G-4

Capital Cost Estimates for a 2000 Tons Per Day Purox System

Title	Input-output category	SIC code	Cost in 1976 dollars (millions)	Deflator from Aug. 1976 to Sept. 1974	Costs in Sept. 1974 dollars (millions)	Costs in Sept. 1974 dollars (millions) for a 6000 TPD facility
Sawmills and Planing Mills General Products	20.02	2421	.50	.87	.43	.92
Concrete Products and Ready-Mixed Concrete	36.11 36.12	3272 3273	4.51	.83	3.76	7.99
Heating Eqpt except electric	40.03	3433	2.40	.89	2.13	4.54
Fabricated Structural Steel	40.04	3441	4.86	.89	4.34	9.21
Fabricated Plate Work	40.06	3443	4.91	.89	4.38	9.30
Fabricated Metal Products	42.05 42.08 42.11	3481 3494,3498 3499	5.14	.89	4.58	9.73
Materials Handling Machinery and Eqpt	46.02 46.03	3535 3536	6.63	.90	5.98	12.70
General Industrial Machinery and Eqpt	49.01 49.03 49.07	3561 3564 3569	5.67	.92	5.22	11.09
Motors and Generators	53.04	3621	1.08	.95	1.02	2.17
General Machinery, Controls, and Electrical Apparatus	48.06 53.05 53.08	3559 3622 3629	11.12	.95	10.57	22.46
Labor Cost			23.62	.89	21.05	44.73
Professional Service Cost	73.03	8100 8900 (ex. 8921)	4.81	.89	4.33	9.20
TOTAL			75.25		67.73	144.03

Source: Figures are aggregated from data for the Purox System supplied by the Union Carbide Corporation, Linde Division.

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2. Fisher, T.F., et al., "The Purox System," Union Carbide Corporation, September 1975.

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